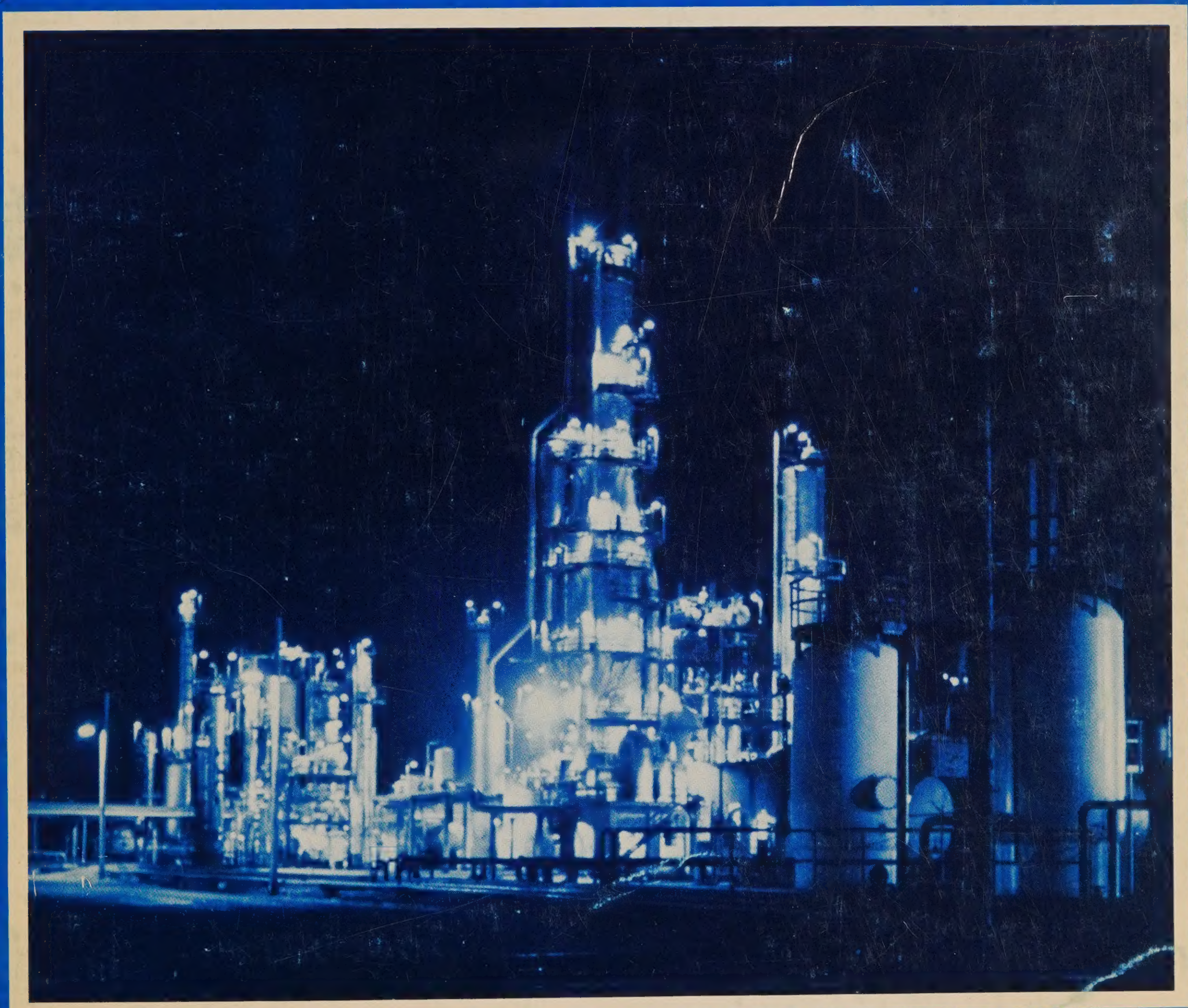
CANADIAN OIL

Supply and Requirements



National Energy Board
September 1975

PHOTO-CREDIT: Phototeck, Information Canada

CANADIAN OIL SUPPLY and REQUIREMENTS

National Energy Board

September 1975

"The Board may of its own motion inquire into, hear and determine any matter of thing that under this Act it may inquire into, hear and determine."

National Energy Board Act
Part I, Subsection 14(2)

"The Board may hold a public hearing in respect of any other matter if it considers it advisable to do so."

National Energy Board Act
Part I, Subsection 20(3)

"In the Matter of an enquiry, hearing and determination of the producibility of Canadian oil, the domestic demand for oil and for indigenous feedstocks, the effects of conservation on Canadian consumption, the surplus of Canadian oil, and related matters."

National Energy Board Act
Order OHR-1-75, dated 20
February, 1975.

Contents

List of Appendices

Counsel and Witnesses

A public hearing in the matter of the producibility of Canadian oil, the domestic demand for oil and for indigenous feedstocks, the effects of conservation on Canadian consumption, the surplus of Canadian oil, and related matters held pursuant to Part I of the National Energy Board Act.

File: 1722-9-1

HEARD at Calgary, Alberta on 15, 16, 17, 18 April 1975
Ottawa, Ontario on 22, 23, 24, 25 April 1975

BEFORE:

J.G. Stabback	Associate Vice-Chairman
R.F. Brooks	Member
W.A. Scotland	Member

APPEARANCES:

Calgary	D.E. Lewis, Q.C. H.S. Simpson	Canadian Petroleum Association (C.P.A.)
	R.W. Hayes R.G. Kessler	BP Exploration Canada Limited (B.P.)
	R.R. Andrews W.G. Loewen	Dome Petroleum Limited (Dome)
	G.A. Johnson R.R. Mahaffey J.D. Scott	Chevron Standard Limited (Chevron)
	R.N. Gimby M.L. Johns A.G. Morrison	Home Oil Company Ltd. (Home Oil)

Calgary	J.L. Gaffney J.C. Gateman K.W. Lloyd R. Sedgewick	Hudson's Bay Oil and Gas Company Limited (HBOG)
	E.R. Blasken C.A. Jameson	Husky Oil Operations Ltd. (Husky)
	G.C. Derbowka H. Groeneveld J.A. Kelly D.W. McFarlane	Mobil Oil Canada Ltd. (Mobil)
	E. Molnar D.W. Rowbotham G. Thompson	Pacific Petroleums Ltd. (Pacific)
	P. Carpenter B.W. Jones I. Martin	PanCanadian Petroleum Limited (PanCanadian)
	P. Massarotto W. Muscoby	Texaco Exploration Canada Ltd. (Texaco Exploration)
	R.J. Christiensen R.L. Harrop	Sulpetro of Canada Ltd. (Sulpetro)
	P.J. Benn J.M. Killey H.J. Lyon C.R. Mattinson L.J. Schofield	Shell Canada Limited (Shell)
Ottawa	A.J. Dingley A.J.W. Hepworth J. Ludgate	British Columbia Energy Commission (B.C. Energy Commission)

Ottawa	P. Black E.G. Dennison J.A. Griffin	Government of Saskatchewan (Saskatchewan)
	G.A. Connell J.R. Dunnet W.K. Good J.R. Hardie A.F.D. Short	Gulf Oil Canada Limited (Gulf)
	J. Koshan D.D. Lougheed R.M. Maier R.G. Niven L.C. Sevick	Imperial Oil Limited (Imperial)
	R. Humphreys	Sun Oil Company Limited (Sun)
	J.A. Bray V. Millard	Alberta Energy Resources Conservation Board (AERCB or Alberta Board)
	S.M. Farouq Ali R.G. Farquharson R.T. McLean L. Pasychny	Murphy Oil Company Ltd. (Murphy Oil)
	H.H. Harper	Standard Oil Company of British Columbia Limited (SOBC)
	W. Beaudry J.G. Pashniak	Texaco Canada Limited (Texaco)
	R.H. Clendining W.B. Gill, Q.C. P.E. Pinnington I.H. Rowe	Ministry of Energy for Ontario (Ontario)

Ottawa	J.D. French V.L. Harnish	Nova Scotia Energy Council (N.S. Energy Council)
	W.S. Hunter G.K.F. Pepper W.J. Stewart, Q.C.	Ontario Hydro

Introduction

A comprehensive hearing on the subject of the exportation of oil was held by the National Energy Board ("NEB" or the "Board") in April and May 1974 and the findings were released in a report in October of that year.

One of the conclusions of the report was that public hearings should be held periodically to receive evidence with respect to the potential producibility of Canadian oil, the domestic demand for indigenous feedstocks and the effects of conservation on Canadian consumption and surplus. The first of these periodic hearings was held in April, 1975 in Calgary and Ottawa under Part I of the National Energy Board Act.

Thirty companies, individuals, and government agencies filed submissions in response to the Notice of Hearing (Appendix A) issued on 17 January, 1975.

This is a report of the evidence presented to the Board and its findings on the subject matters of the hearing.

Supply

This section of the report deals with the views received and the Board's views concerning all matters related to item I of the Board's suggested Outline for Submissions (Appendix B). The various oil supply categories are discussed in the following order:

a) established reserves in conventional areas,

b) additions to established reserves in conventional areas,

c) pentanes plus reserves,

d) oil sands deposits,

e) frontier reserves.

Established Reserves in Conventional Areas

i) Views of Submittors

The views of submittors regarding this category of reserves were mainly embodied in completed forecasts for individual pools showing producibility and reserves estimates in the form requested by the Board in its Outline for Submissions (Appendix B). These forms made provision for the display of an oil producibility forecast to 1994 with sufficient reservoir data to support the forecast and for an indication of the potential for reserves appreciation for each pool. The Board requested these data from the major operators of some 160 individual pools. Independent estimates were received from the British Columbia Energy Commission ("B.C. Energy Commission"), the Alberta Energy Resources Conservation Board ("AERCB" or "Alberta Board"), and the Government of Saskatchewan ("Saskatchewan"). Completed data forms were received for about 95 percent of the pools listed in the Outline for Submissions. In addition, data were provided on other pools which submittors felt should be included.

Evidence contained in the submissions was supplemented by verbal testimony at the hearing in response to questions asked by Board counsel.

The individual pool data obtained through submissions and testimony are not shown in this report, but they are available for public inspection at the Board's offices in Ottawa and Calgary.

ii) Views of the Board

In light of the evidence received, the Board modified its initial list of pools. Several were deleted and others added to give a final list of 163 individual pools and units grouped by feeder pipeline system. The remaining pools, not studied in detail, were placed in 28 "other" categories classified according to feeder pipeline system. The 163 pools given detailed study account for about 88 percent of the total established reserves in Canada.

In its October, 1974 report the Board defined producibility as "the estimated average annual ability to produce, unrestricted by demand but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity." Where production is restricted for prolonged periods to levels below potential, it is acknowledged that cost considerations will militate against the maintenance of surplus capacity for immediate availability. However, certain well remedial work and minor facility debottle-necking could be carried out to improve producibility within a period of 60 to 90 days. The Board believes it is appropriate to include such improvements within the definition of producibility. Accordingly, "potential producibility" or "producibility", as used in this report, is that producing level which could be achieved on 90 days' notice. Forecasts of producibility levels relate to those wells and facilities which are now in place, together with those resulting from development programs with a high degree of probability of completion attached.

Reserves estimates are essential elements in preparing a long-term producibility forecast. They have been published for many years by provincial regulatory agencies and by the Canadian Petroleum Association ("C.P.A."). These reserves statistics provide a continuing record of hydrocarbon discovery trends and have been useful to industry and government for policy formulation and decision making. In Alberta, these reserves estimates were especially important as they were used for allocating production among pools during periods when producibility was greater than market demand. The Board has, in the past, monitored oil reserves as part of its advisory function. Prior to the commencement of the current protection procedures on 1 January, 1975 the Board had not published its own reserves estimates. However, since these reserves estimates are a factor in the calculation of producibility used in the protection procedure, the Board now

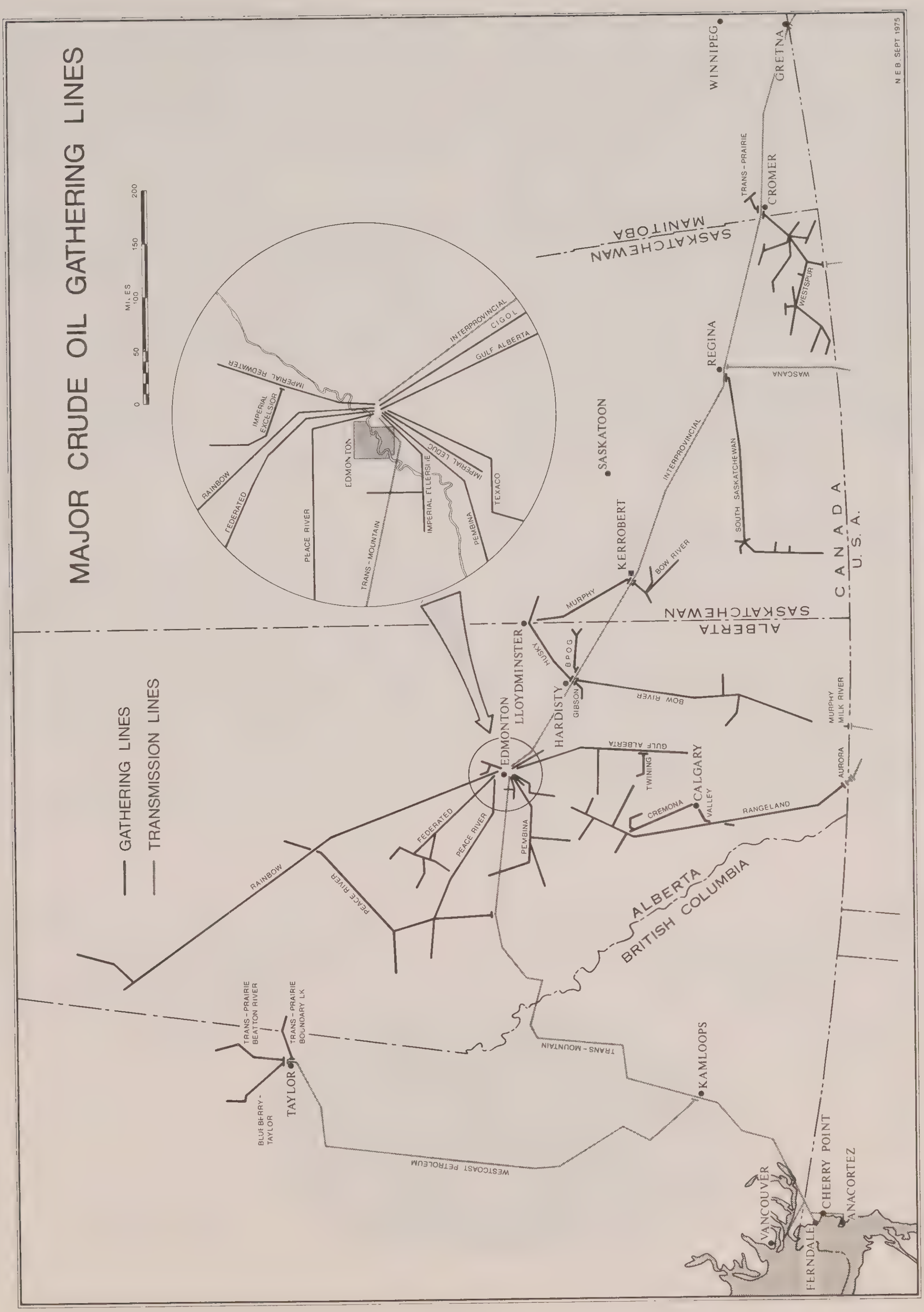


Figure 1: Major Crude Oil Gathering Lines.

sees merit in publishing its reserves estimates. The Board has taken into account the reserves evidence received at the hearing in making its current estimates of reserves. These estimates are shown in Appendix C on a pool-by-pool basis by province and territory and total some 6.9 billion barrels as of 1 January, 1975. They have been grouped by pipeline system to correspond with the producibility forecasts. The location of these pipeline systems is shown in Figure 1. The relative significance of the reserves attributable to the 12 largest pipeline systems is illustrated in Figure 2.

The volumetric and material balance methods of calculating oil reserves are well established and widely used by industry and regulatory agencies, including this Board. In recent years, the use of computer reservoir performance simulators has assisted in the calculation of reserves. The calculations involve many measurements and assumptions including area of the reservoir, pay thickness, porosity, initial and residual gas, oil and water saturations, relative permeabilities, reservoir energy, depletion mechanisms and sweep efficiency. The degree of confidence applicable to estimates of reserves is reflected in the use of such terms as proven, probable, and potential. However, even within a particular classification there is considerable room for divergence of opinion. To identify uniquely its own estimates, the Board has adopted the term "established reserves" as defined in the October, 1974 report.

Forecasting producibility from reserves involves assumptions on an individual pool basis regarding well spacing, reservoir fluid flow, pressure maintenance, well and surface facilities, and market demand. Regardless of the level of peak producibility achieved, producing rates will begin to decline over time.

To collect and summarize pool potential producibility forecasts, the Board has developed a simple model which was explained in the October, 1974 report. Briefly, the model considers three stages of reservoir depletion: a period of increasing production early in the reservoir life, a period of constant annual production at a peak rate, and a period of declining producibility. The decline portion can be characterized by any of the three classical types* of decline equations; exponential (also called constant-percentage), hyperbolic and harmonic.

It is generally acknowledged that the selection of producibility decline patterns is not as precise a science as the calculation of reserves. Accordingly, one of the items on which the Board sought advice during the hearing was the selection of appropriate decline curves. Some witnesses stated that company forecasts were based on detailed reservoir model studies. It is the Board's opinion that even in such studies the forecast is dependent on the correlations and assumptions

*Arps, J.J., "Estimation of Primary Oil Reserves", Petroleum Transactions, AIME, Vol. 207, 1956, p. 189.

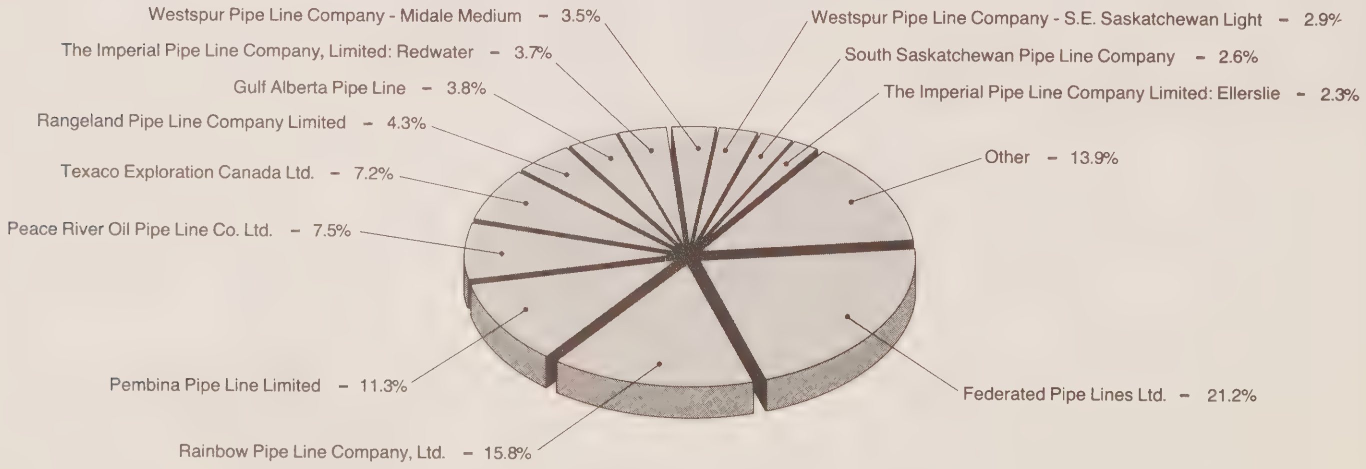


Figure 2: Remaining Established Crude Oil Reserves By Pipeline System as of January 1, 1975.

chosen for the mathematical model, and is thus influenced by the judgment of the user. Model studies were requested where appropriate, but not examined in detail at the hearing. Many submittors stated that selection of production decline curves is difficult in view of the current stage of development of Canada's oil fields and the state of the art.

When evaluating the pool producibility declines submitted in evidence, the Board made use of the work of H.M. Mead* who found that decline curve shapes can be correlated with the predominant type of reservoir production mechanism. Mead suggested that decline curves progressed from exponential, through hyperbolic, to harmonic in the following order of drive mechanism:

- pressure maintenance by water
- pressure maintenance by gas
- gravity drainage
- gas cap drive
- solution gas drive

Since the majority of reservoirs considered in this report have waterflood schemes in operation, or have naturally occurring strong water drives, the Board's forecasts tend to be dominated by exponential declines. This tendency towards the use of exponential declines was checked for each producing are against the evidence, historical performance, analogy with other pools, and model studies to ensure the appropriateness of adopting a constant annual decline rate. For example, some low permeability and/or highly stratified reservoirs seem to decline in a strong hyperbolic fashion even with waterfloods in operation.

*Mead, Homer M., "Modifications to Decline Curve Analysis", Petroleum Transactions, AIME, Vol. 207, 1956, p. 14.

After considering all evidence received in the submissions and in verbal testimony, together with information supplied after the hearing, the Board has developed the 20-year pool-by-pool potential producibility forecast shown in Appendix D. The pools are grouped by pipeline, and producibility sub-totals are included for each pipeline system. Figure 3 shows the relative significance of the producibility of the 12 largest pipeline systems. They comprise some 86 percent of the producibility of the 34 pipeline systems shown in Appendix D.

The following 34 graphs compare, by pipeline system, the Board's producibility forecast with the forecasts submitted. The curves labelled "C.P.A." are a summation of industry forecasts for individual pools. The same data as submitted by companies to the Board were also supplied to the C.P.A. for its submission to the Board. In one case, Pacific Petroleums Ltd.'s ("Pacific") forecast for Blueberry-Taylor Pipelines, the data submitted to the Board were slightly different from the data supplied to the C.P.A. Also shown are pipeline forecasts submitted by the B.C. Energy Commission and the AERCB. Saskatchewan did not submit 20-year pipeline forecasts.

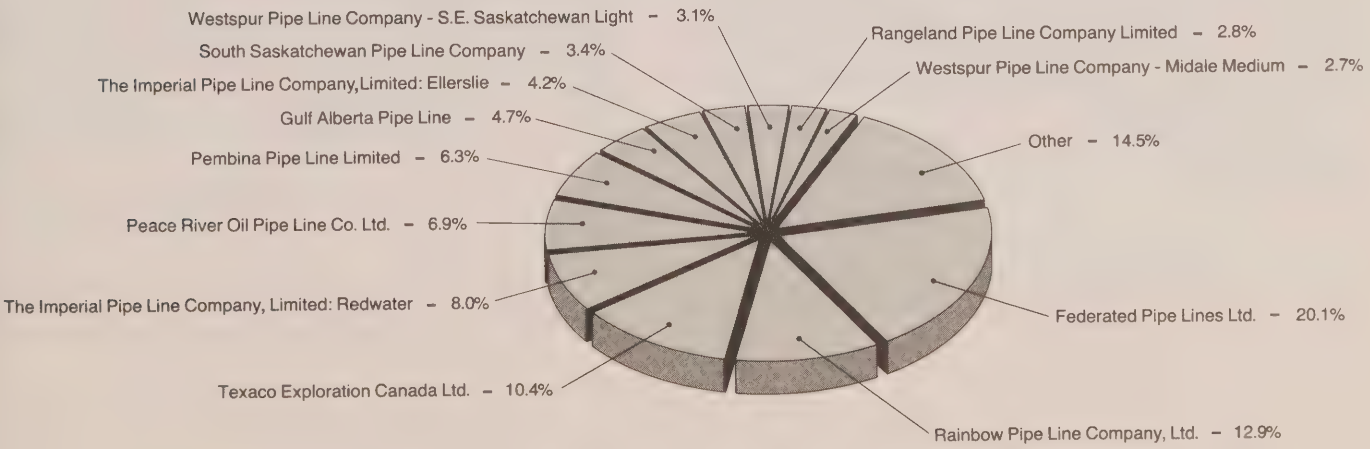
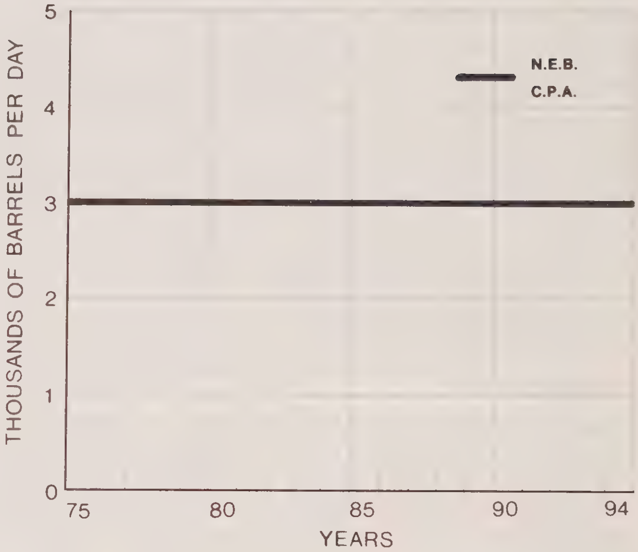


Figure 3: Canadian Crude Oil Producibility By Pipeline System For 1975.

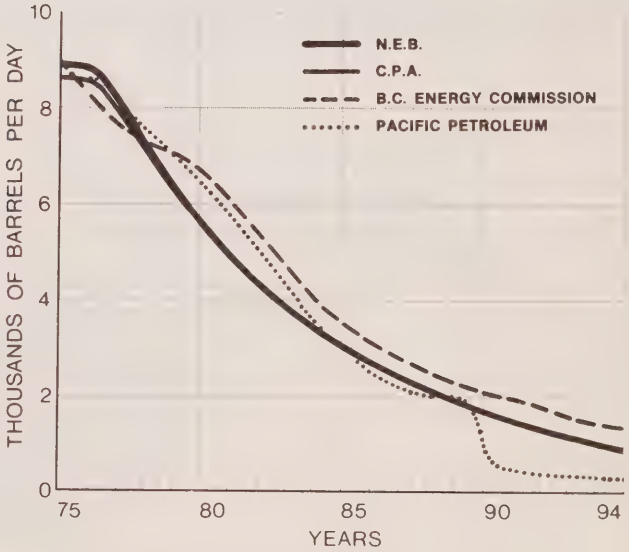
The following discussion of the Board's producibility forecast is segmented by territory or province and by pipeline system (and oil batch), and in the interests of brevity, covers only the most significant aspects of the forecast.

NORTHWEST TERRITORIES



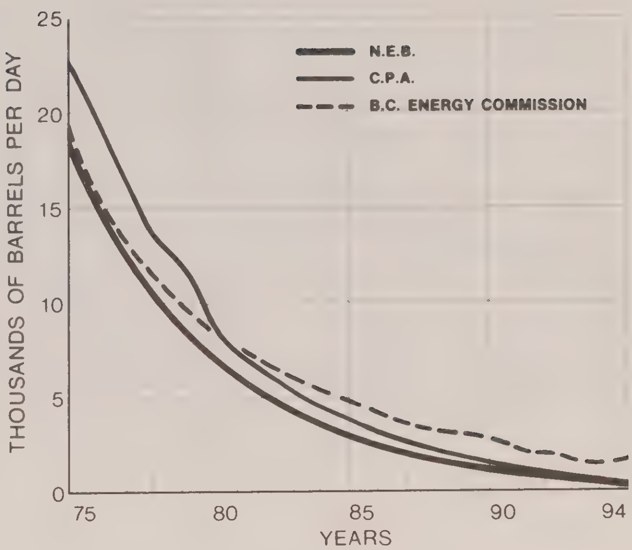
Norman Wells: *This pool has experienced an annual production growth rate of about five percent, with reserve potential for continued production growth in the future. However, at the hearing Imperial Oil Limited ("Imperial") indicated that under existing economic conditions it was not contemplating any refinery expansion to allow for increased production levels. Accordingly, the Board is forecasting a production plateau at the current level.*

BRITISH COLUMBIA

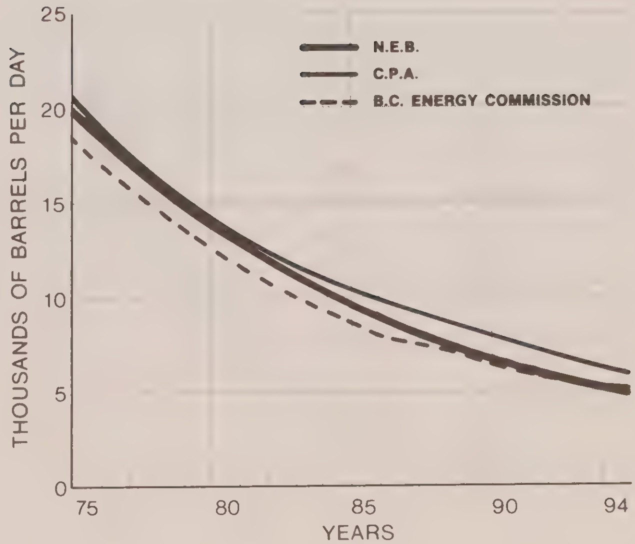


Blueberry-Taylor Pipelines: *This is a mature producing area where production from all major pools is on the decline. There are no major disagreements between the Board's analysis of reserves and producibility for these pools and the data submitted by industry and by the B.C. Energy Commission.*

Trans-Prairie Pipelines Ltd.: Beatton River-Taylor: *This is also a mature producing area with all of the major pools on production decline. Again, there are no major disagreements between the Board's analysis of reserves and producibility and the data submitted by industry and by the B.C. Energy Commission.*

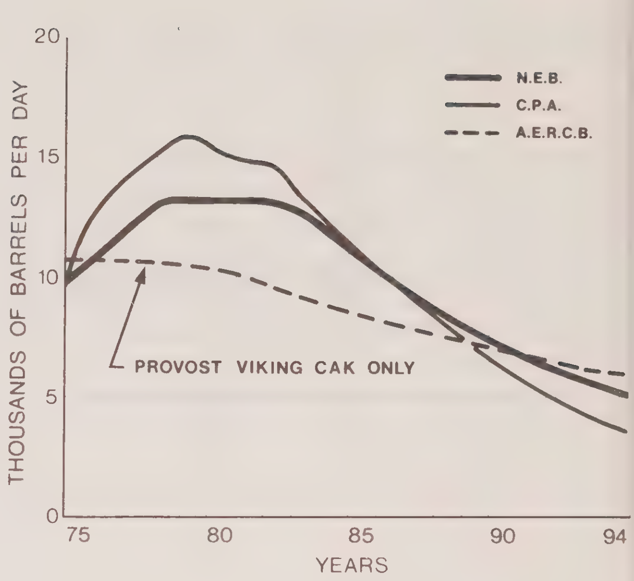


Trans-Prairie Pipelines Ltd.: Boundary Lake-Taylor: *The Board's reserves estimate for this area is some 18 percent below the industry estimates provided by Texaco Exploration Canada Ltd. ("Texaco Exploration") and Imperial and 23 percent below the B.C. Energy Commission estimate. The latter estimate includes both proved and probable reserves, with probable reserves accounting for one third of the total. Because of the expected long life of these reserves, the differences in reserves estimates yield only minor variations in potential producibility over the forecast period.*

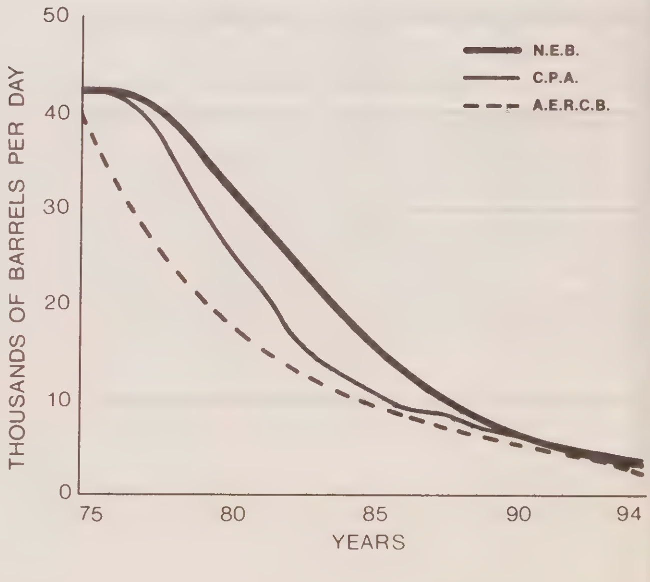


ALBERTA

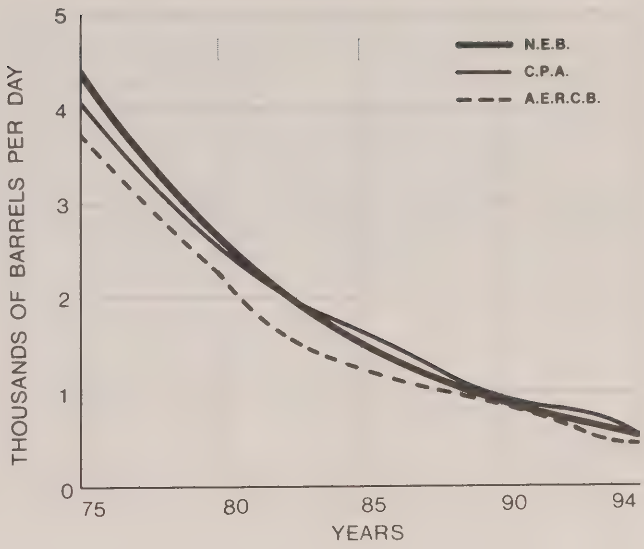
Bow River Pipe Lines Ltd., Light & Medium: *Most of the production in this pipeline batch comes from the Provost Viking CAK pool. There has been a threefold production increase from this pool over the interval 1969-1974. The AERCB forecast suggests that production will not exceed existing levels, while the forecast provided by Chevron Standard Limited ("Chevron") indicates an increase in production from 10,500 barrels per day ("b/d") in 1975 to 15,450 b/d in 1977. The Board forecast recognizes a potential for producibility growth to 13,000 b/d by 1978. The AERCB line on the graph is for the Provost Viking CAK pool only. The other two projections include the other light and medium production, which in 1974 was some 200 to 300 b/d.*



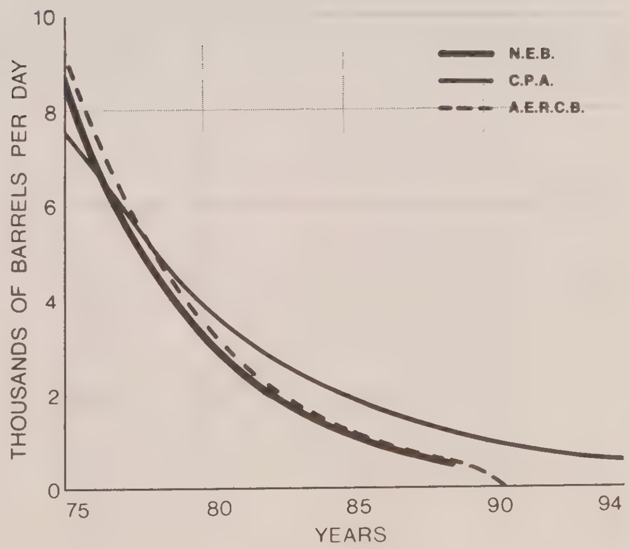
Bow River Pipe Lines Ltd., Heavy: *This is a relatively immature heavy oil producing area, with waterflooding having commenced very recently in many of the pools. The area has potential for increased waterflood response and for new waterflood schemes. PanCanadian Petroleum Limited ("PanCanadian") stated that market uncertainty has caused a delay in implementing two of its new waterfloods. The significant differences in the forecasts for this pipeline can be attributed in large part to the assumptions made regarding future markets for this heavy crude.*



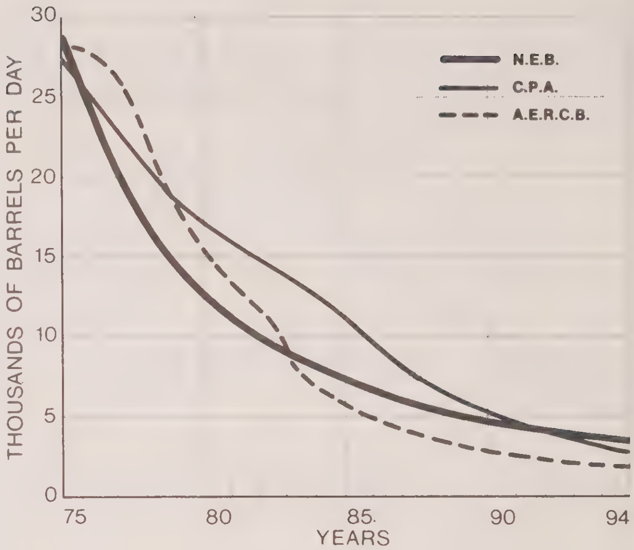
BPOG Operations Ltd.: *The major heavy oil pools producing into this pipeline system are all on established production declines, and there were no significant differences in reserves or producibility among the forecasts.*



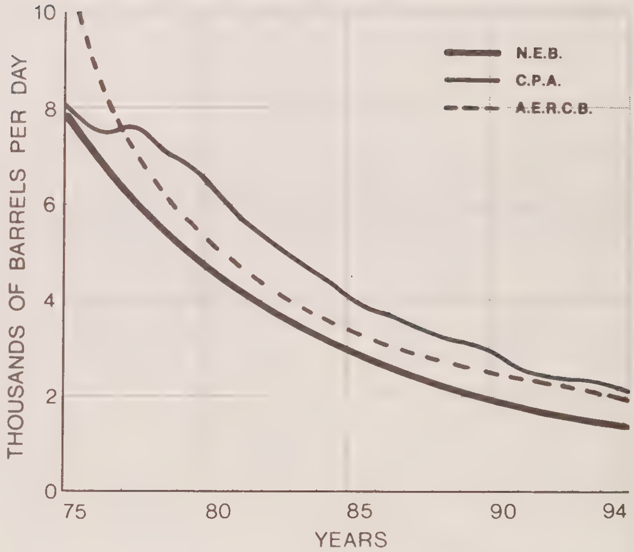
Canadian Industrial Gas and Oil Ltd.: *The differences in forecast producibility for the Joarcam Viking pool are due primarily to differing estimates of the remaining reserves. The AERCB estimates 15.1 million stock tank barrels ("MMstb"), and the industry estimate provided by Imperial is 20.9 MMstb. The Board estimates remaining established reserves of 15.3 MMstb.*



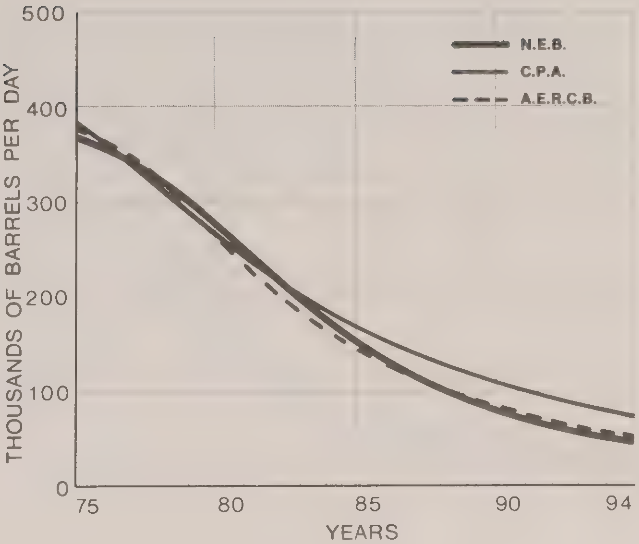
Cremona Pipeline: *On the basis of studies of reserves in this area, and an analysis of decline patterns in similar pools, the Board felt it was reasonable to use hyperbolic declines for the Cardium and Rundle formations. This conclusion is consistent with the evidence received at the hearing. The Board and the AERCB forecasts are considerably lower than industry's forecast for the early 1980's, but otherwise there are no major disagreements in reserves or producibility.*



Gibson Petroleum Company Limited: *The Board's potential producibility forecast for this pipeline is somewhat lower than those provided by the AERCB and by industry. This can be attributed to the difference in assigned reserves for the Bellshill Lake Pool, and the Board's assessment of the steps that will be taken to maintain or increase producibility.*



Federated Pipe Lines Ltd.: *This system ranks first in terms of potential producibility and is estimated to be able to contribute one fifth of the total for Canada in 1975. The individual pools considered for this pipeline are generally at the point of being one third depleted.*



The Board's potential producibility forecast is in close agreement with those of industry and the AERCB during the first half of the 20-year forecast period. The divergence between the producibility forecasts of the Board and industry during the second half of the forecast period can be attributed to the Board's lower assessment of reserves. These differences are major as can be seen in the following table:

There are differences of opinion on two of the parameters used to calculate reserves for Beaverhill Lake ("BHL") reservoirs. One is the residual oil saturation and the other is the sweep efficiency of a waterflood. Because of the range of expert opinions regarding both factors and in view of the early stage of depletion in these complex reservoirs a conservative approach has been adopted by the Board.

REMAINING ESTABLISHED RESERVES — MMstb

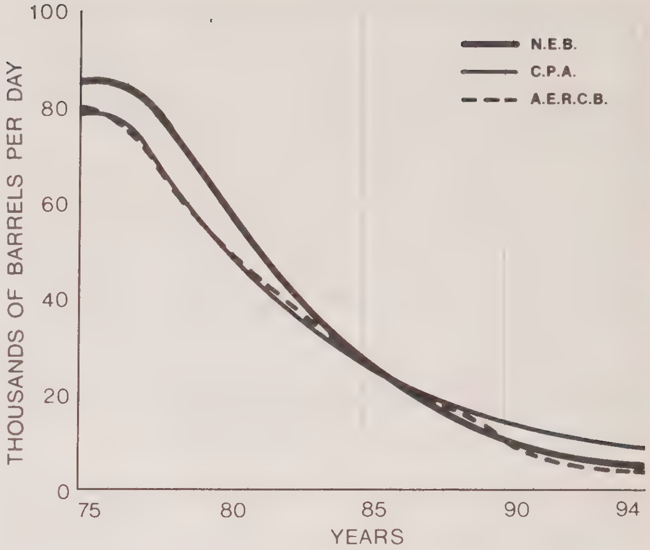
	NEB	AERCB	INDUSTRY*
Carson Creek North — BHL A	24.5	21.3	33.5 (Mobil)
Carson Creek North — BHL B	82.3	73.0	114.0 (Mobil)
Judy Creek — BHL A	236.7	236.6	330.2 (Imperial)
Judy Creek — BHL B	74.8	74.8	94.8 (Imperial)
Swan Hills — BHL A & B	497.5	522.5	578.7 (Home)
Swan Hills — BHL C	127.2	130.2	127.2 (Shell)
Swan Hills South — BHL A & B	306.0	367.2	376.9 (Amoco)**
Virginia Hills — BHL	83.1	102.1	123.1 (Shell)
***Total	1,432.1	1,527.7	1,778.4

*Companies named supplied forecasts used by the C.P.A. in its submission

**Obtained from Amoco Canada Petroleum Company Ltd. but not given in evidence at the hearing

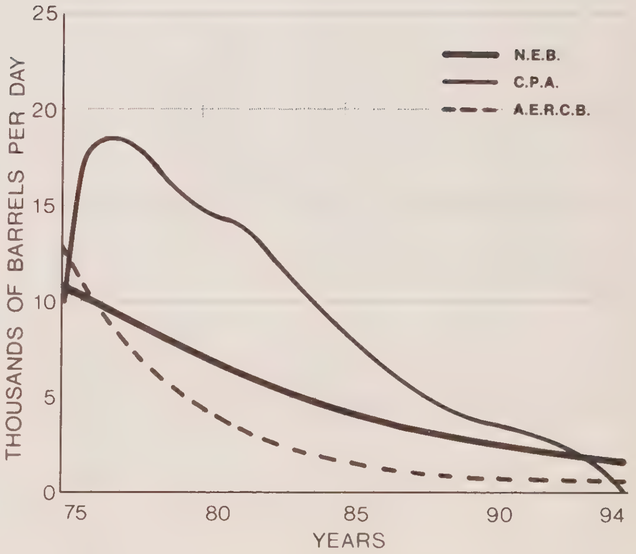
***Not equal to the total for the pipeline system as it excludes approximately 30 MMstb from smaller pools

Gulf Alberta Pipe Line: *The Board's potential producibility forecast is slightly higher than both the AERCB and industry estimates for the period prior to 1983. In the case of the AERCB estimate, this is primarily due to a difference of 3000 b/d for the peak rate assigned to the Fenn Big Valley D-2A pool.*

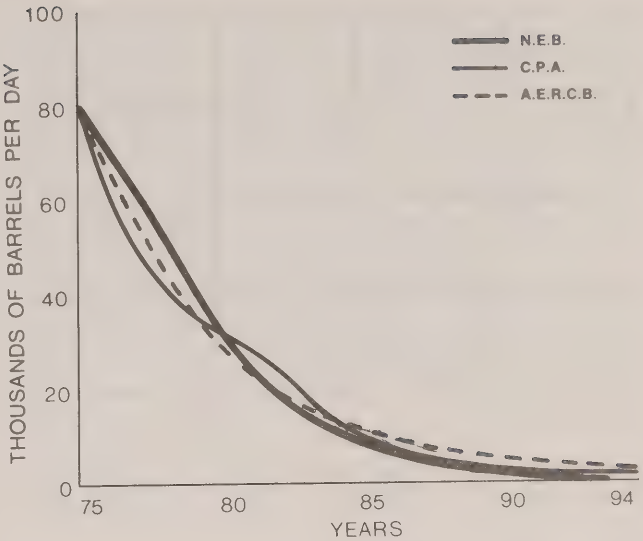


Husky Pipeline Ltd.: *Comparison of cumulative production and reserves data submitted by industry and the AERCB for the Lloydminster Sparky C and GP A and the Lloydminster Sparky and GP C pools is not possible because the industry data provided by Husky Oil Operations Ltd. ("Husky") did not cover the total area assigned to these pools by the AERCB. The Board's forecasts are consistent with the AERCB's pool definitions.*

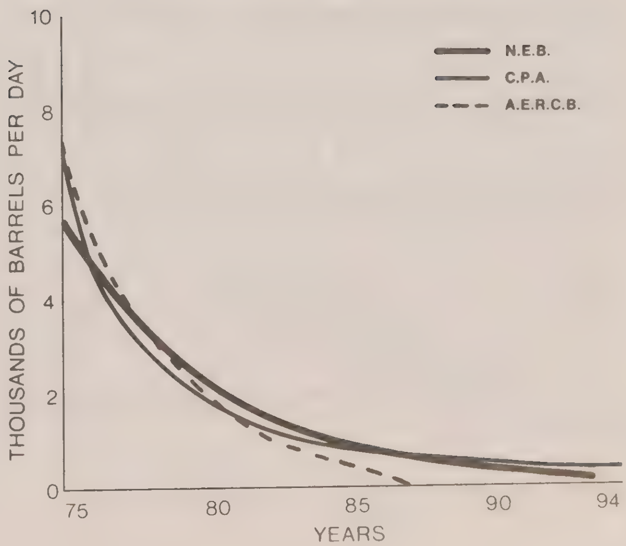
The Board's potential producibility forecast is significantly lower than the industry forecast for the pipeline system. This is due to the fact that the Board's forecast does not, as yet, recognize the proposed development program by Pacific for the Buffalo Creek field.



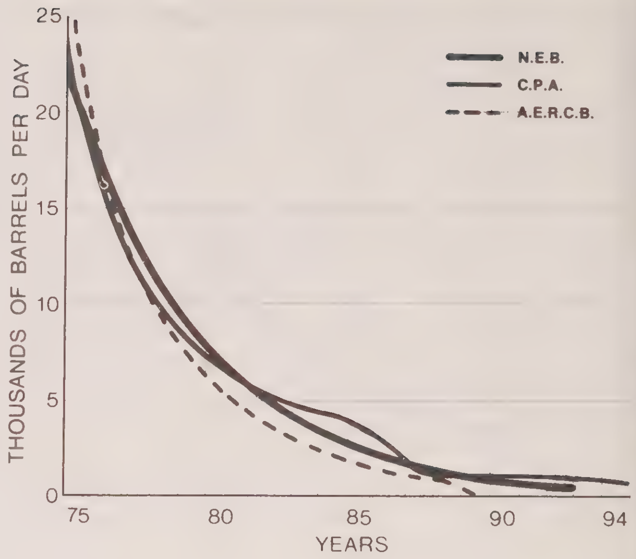
The Imperial Pipe Line Company, Limited — Ellerslie: *The Board's potential producibility forecast is slightly higher than those of industry and the AERCB over the period from 1976 to 1982 and slightly lower in the years following 1982. This is primarily due to the Board's lower decline rates for the pools within this pipeline system. The Board's assignment of remaining reserves of 81.8 MMstb for the Golden Spike D-3A pool is based on a recent review of pool performance by the Board's staff. These reserves are slightly lower than the remaining reserves of 88.8 MMstb estimated by Imperial and significantly lower than the AERCB's current published estimate of 150.8 MMstb.*



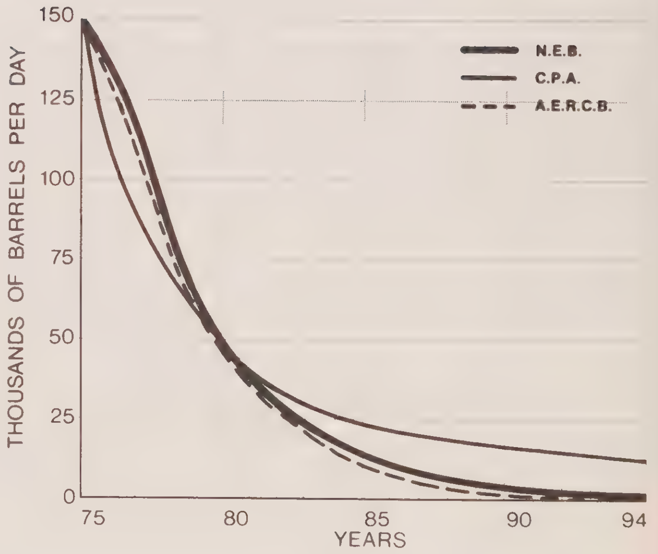
The Imperial Pipe Line Company, Limited — Excelsior: *For the Excelsior D-2 and Fairydell Bon Accord D-3A pools the Board has assigned a slightly lower producing potential for the current year, and lower decline rates than either industry or the AERCB indicated in their submissions.*



The Imperial Pipe Line Company, Limited — Leduc: *The Board's potential producibility forecast closely approximates the forecasts submitted by industry and the AERCB. The Board, as well as the AERCB, has used harmonic declines for the Leduc D-2A pool. However, the Board's assignment of remaining reserves of 1.7 MMstb for this pool is far lower than the AERCB estimate of 7.5 MMstb, and approximately half of the value of 3.2 MMstb submitted by Imperial. The AERCB (at 25.9 MMstb) is currently estimating slightly lower remaining reserves for the Leduc D-3A pool than Imperial (29.0 MMstb) and the Board (32.0 MMstb).*

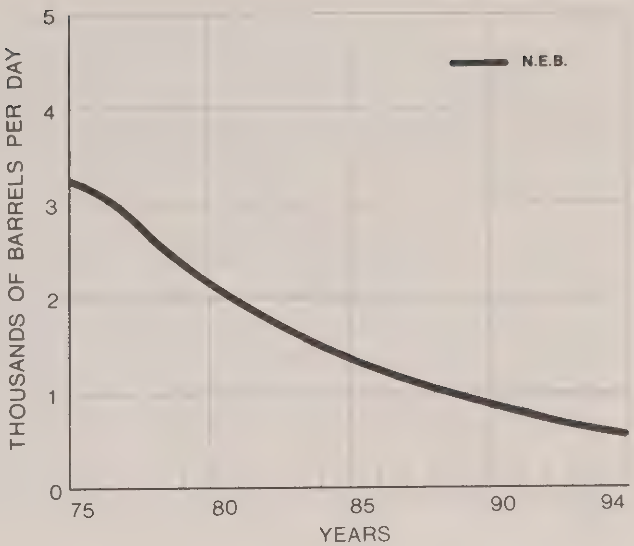


The Imperial Pipe Line Company, Limited — Redwater: *The Board's forecast of crude oil potential producibility from the Redwater D-3A pool is very similar to the AERCB forecast, but exceeds the forecast submitted by Imperial during the years from 1975 to 1980. However, beyond 1981 Imperial's forecast maintains higher levels of producibility than either the Board or the AERCB forecast. This is due to two factors; the lower producibility rates estimated by Imperial in the initial years and Imperial's estimate of remaining reserves of 307.3 MMstb which is 42.0 MMstb greater than the AERCB's current remaining reserves of 265.3 MMstb for the Redwater D-3 pool. The Board currently recognizes 256.4 MMstb as the remaining reserves.*

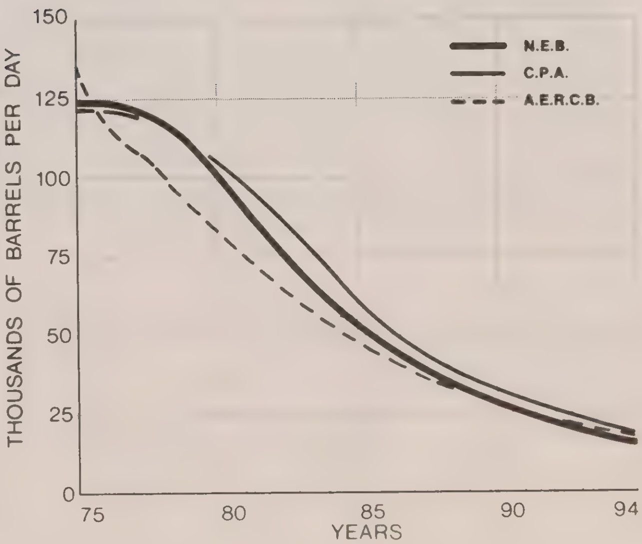


Murphy Milk River Pipe Line: *The Board's potential producibility forecast for this pipeline includes those pools whose production is connected into the pipeline or is trucked to loading terminals on the pipeline. The inclusion of the Manyberries field production in the Milk River line reflects the recent redirecting of production from this field to the truck terminal at the Canadian end of the line. The portion of Cessford production handled by Murphy, and shipped to Calgary, is included under Truck and Tank Car.*

The redefinition of oil pools included in this system precludes a meaningful comparison with the industry and AERCB data.

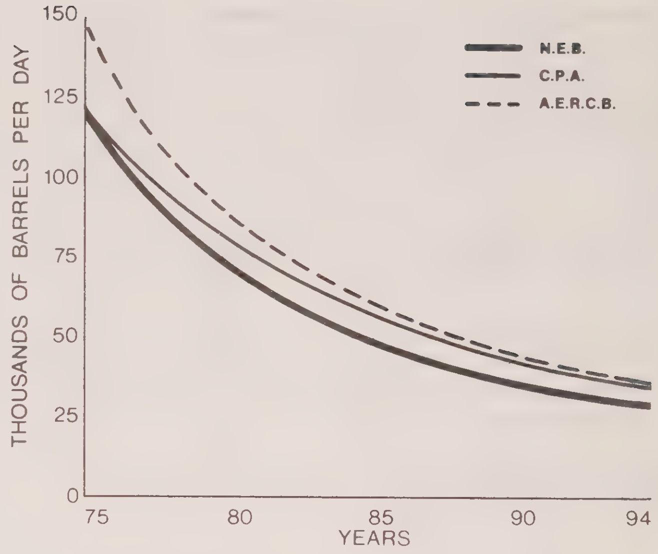


Peace River Oil Pipe Line Co. Ltd.: *The Peace River Oil Pipe Line ranks fifth in terms of potential oil supply in 1975 as shown in Figure 3 on page 5. By 1980, it is expected to rank fourth in potential producibility, indicating the relatively early stage of depletion of pools served by the line. Differences among the pool forecasts relate to the timing and rate of production decline. The AERCB expects these pools to commence declining earlier than forecast by industry or the Board.*

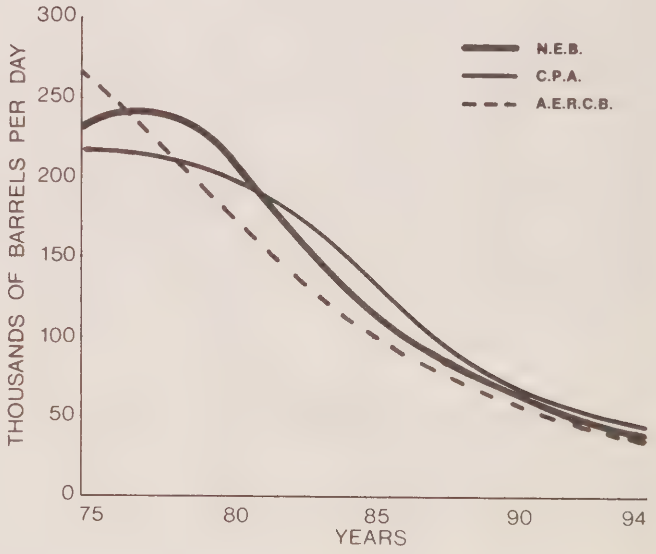


Pembina Pipe Line Ltd.: *The most significant fraction of the potential producibility forecast for the Pembina pipeline system comes from the Pembina Cardium pool. This is the largest pool in Canada, with published reserves estimates indicating remaining reserves ranging from 533.4 MMstb to 1444.6 MMstb.*

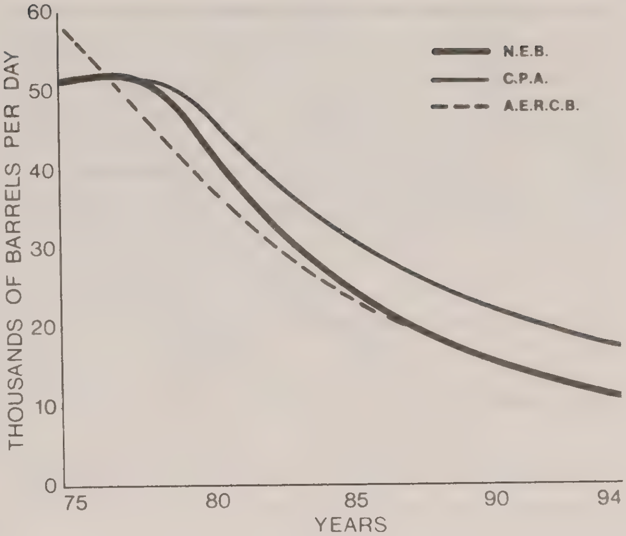
The Board's potential producibility forecast for the Pembina Cardium pool is somewhat more conservative than that of industry and reflects an extrapolation of the pool performance currently being demonstrated. In view of the rapidly increasing watercut and declining production, the Board has estimated established remaining reserves of 598.5 MMstb. Performance from this pool will be monitored closely to determine if a change in reserves estimate should be made.



Rainbow Pipe Line Company, Ltd.: *The more significant differences among the forecasts for this pipeline are in the potential producibility estimates for the first ten years. These differences appear to be spread uniformly among all the pools. Production in the Rainbow-Zama-Virgo area comes from several hundred small pinnacle reefs and it is not possible to cite any specific reasons for the forecast variations.*

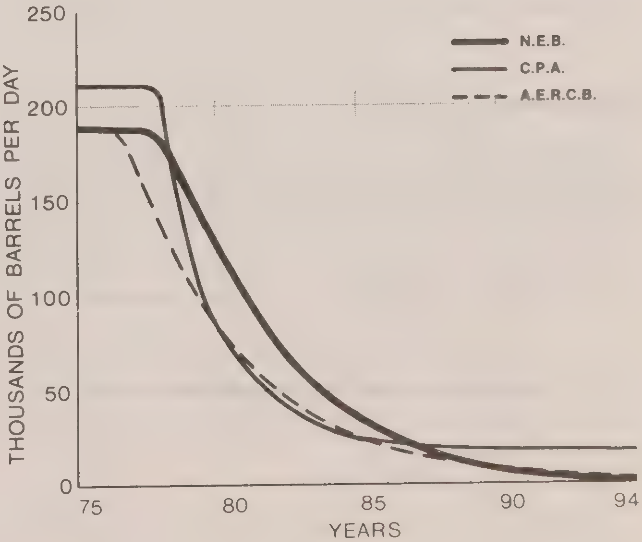


Rangeland Pipe Line Company Limited: *The Board's forecast of reserves and potential producibility for this pipeline system closely approximates the AERCB estimates. The higher industry producibility forecast for later years is due mainly to higher reserves estimates for Innisfail D-3 and Joffre D-2 pools. For the Innisfail D-3 pool, Shell Oil Canada Limited ("Shell") estimated remaining reserves of 47.3 MMstb. The AERCB and the Board are in agreement at 34.3 MMstb. For the 67 percent of the Joffre D-2 pool serviced by Rangeland, Imperial estimated remaining reserves of 32.4 MMstb, while the AERCB and the Board are in agreement at 26.6 MMstb.*



The Board has used hyperbolic declines for the Cardium and Rundle formations within the area served by this pipeline system. In addition, hyperbolic declines were applied to the Gilby Viking A pool, the Gilby Jurassic B pool and the Medicine River Jurassic D pool. Hyperbolic declines were selected by analogy with similar reservoirs or because of the influence of extensive gas caps.

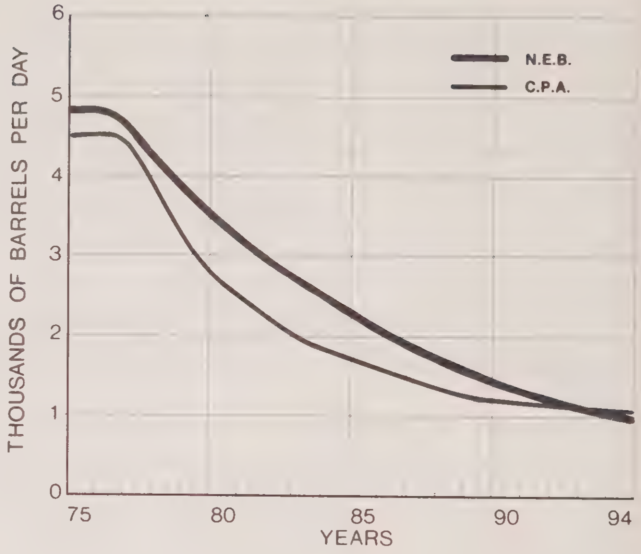
Texaco Exploration Canada Ltd.: *The Board's potential producibility forecast is lower than the industry forecast over the years 1975 to 1977. This is due to the Board's assignment of a lower peak rate in the Bonnie Glen D-3A and Wizard Lake D-3A pools over that period.*



The Board estimates larger remaining reserves for the Bonnie Glen D-3A and Westrose D-3 pools than industry or the AERCB. The larger reserves in Westrose are due to a higher estimate of original oil in place, even though the recovery factor is similar to that used by the AERCB and industry. Larger reserves assignments for the above two pools have affected the Board's potential producibility forecast, by maintaining higher rates over the years 1978 to 1985 than in the industry and AERCB forecasts.

The Board's estimate of established remaining reserves for the Bonnie Glen D-3A pool is 229.9 MMstb, compared with the AERCB's estimate of 213.6 MMstb and Texaco Exploration's estimate of 213.8 MMstb. For the Westrose D-3 pool the comparisons of remaining reserves are: the Board 78.9 MMstb, the AERCB 52.5 MMstb, and Gulf 52.5 MMstb.

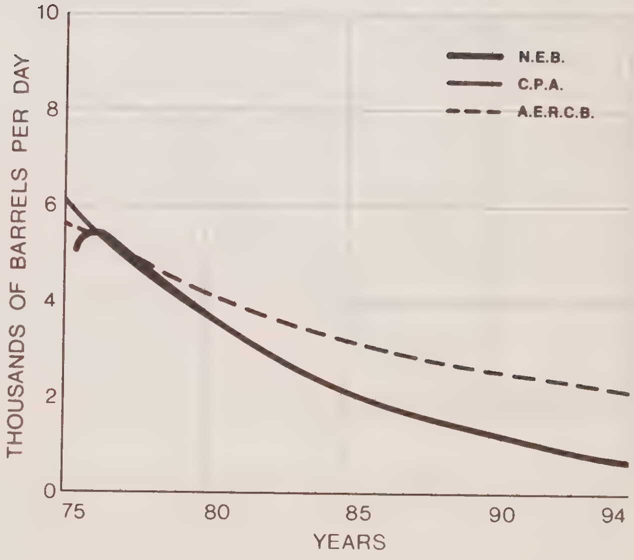
Trans-Prairie Pipelines Ltd., Boundary Lake South: *This pipeline system was added to the list included in the Outline for Submissions. The AERCB did not submit a separate forecast for Boundary Lake South, but included the Boundary Lake South Triassic E pool with its Truck and Tank Car forecast. Industry also assigned Boundary Lake South to a separate pipeline system.*



Twining Pipeline Division: *The Twining Rundle A and Lower Mannville A (L.M.A.) pools were contributing approximately seven-eighths of this pipeline's production at year end 1974. These two pools have undergone development work over the past two years and the total reserves will be subject to change as development continues.*

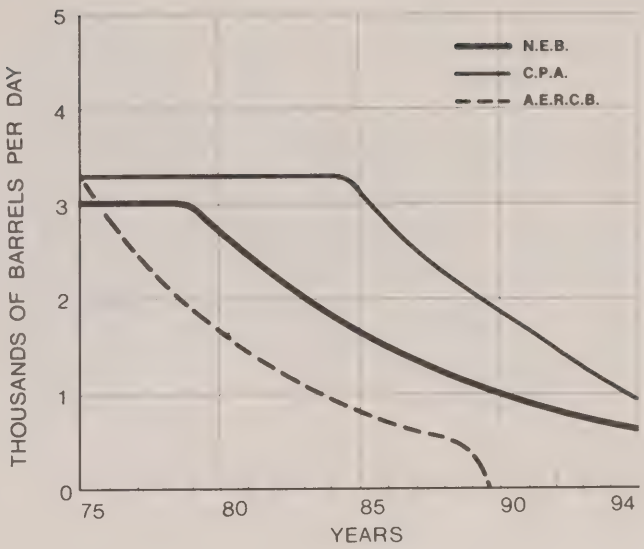
The Board's potential producibility forecast is based on present development plans and agrees more closely with the data submitted by industry than with that contained in the AERCB's submission.

The Board's estimate of established remaining reserves of 18.9 MMstb for the Twining Rundle A and L.M.A. pools agrees with the Hudson's Bay Oil and Gas Company Limited ("HBOG") estimate, but is significantly lower than the AERCB's estimate of 41.3 MMstb.

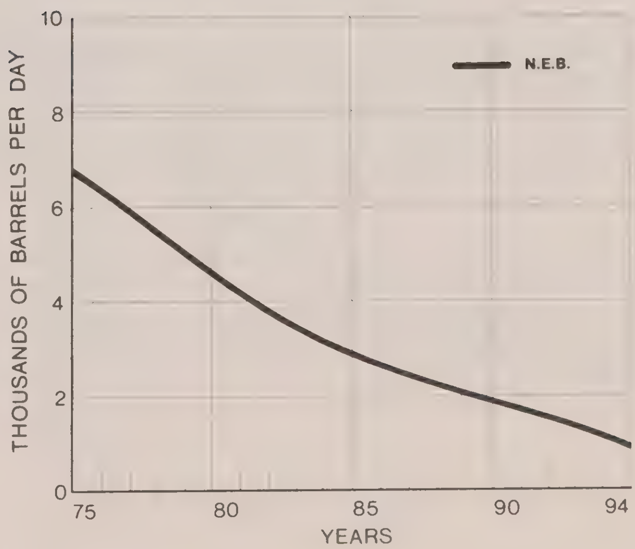


Valley Pipe Line: *The oil production in this pipeline comes exclusively from the Turner Valley Rundle Pool. Industry did not submit a remaining reserves estimate for this pool, but the area under the C.P.A. rate-time curve indicates that a remaining reserves figure in excess of 19 MMstb was used. This is much higher than the Board's estimate of 13.8 MMstb and AERCB's estimate of 6.3 MMstb.*

Historical production data supports a potential producibility forecast which can be described by a period with production at or near present levels from 1975 to 1978 followed by a decline to the economic limit.

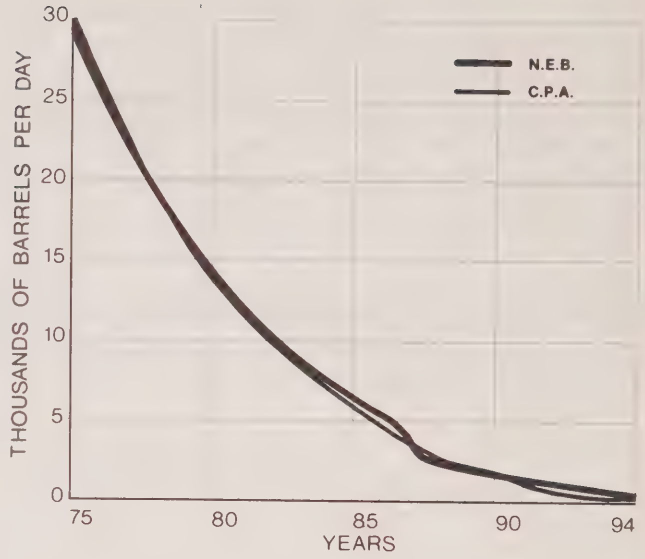


Truck and Tank Car: *The producibility graph shows only the Board's forecast. Industry and the AERCB also provided forecasts but they are not comparable because the pools included are different. Discrepancies involving Cessford, Manyberries and Boundary Lake South have been discussed previously. Several other small pools are also involved. Accordingly, only the Board's forecast is shown.*



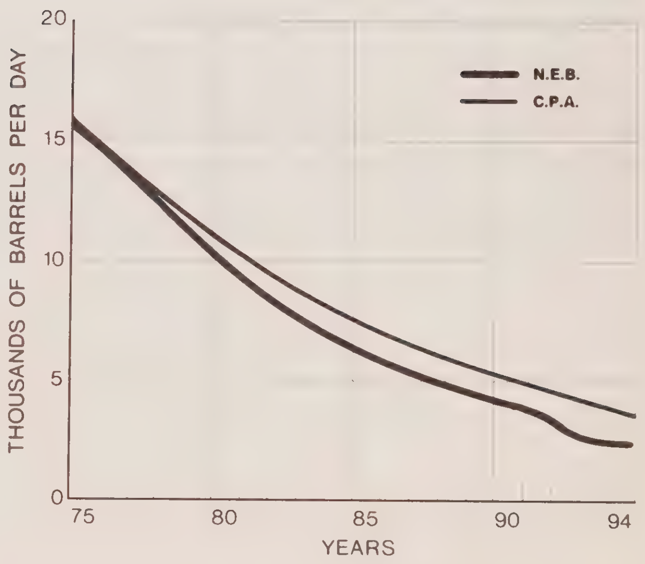
SASKATCHEWAN

Husky Pipeline Ltd. & Murphy Oil Company Ltd.: *The Board's potential producibility forecast is very close to that submitted by industry and projects an average ultimate recovery of 7.5 percent of the oil in place in this area (Saskatchewan's Area I). Because of the unique nature of this producing area, the Board has relied heavily on the operator's evidence regarding oil in place, recovery factors and development plans.*



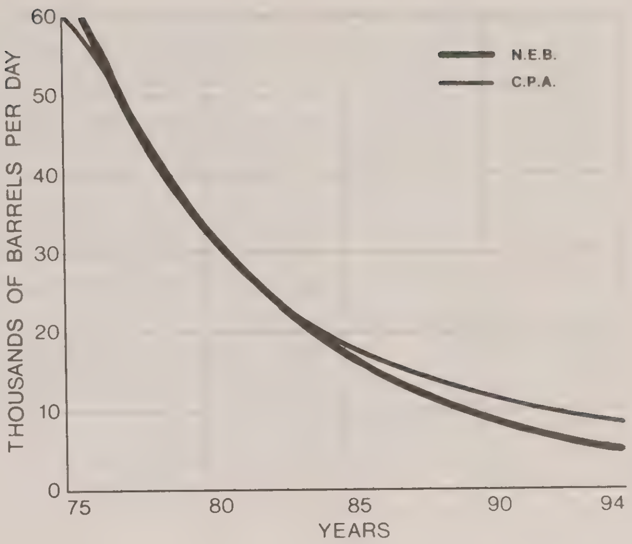
Bow River Pipe Lines Ltd.: *This pipeline system transports crude from both light and heavy oil pools. The Board prepared detailed potential producibility forecasts for significant portions of the major pools producing both types of crude oil but did not separate the forecast by quality, as the crudes are usually marketed as a blend.*

Three new heavy oil producing fields were designated during 1974 within the total region served by the Bow River Pipe Line (Saskatchewan's Area II). Increased producibility attributable to these areas was included in the forecast for the "other" category.

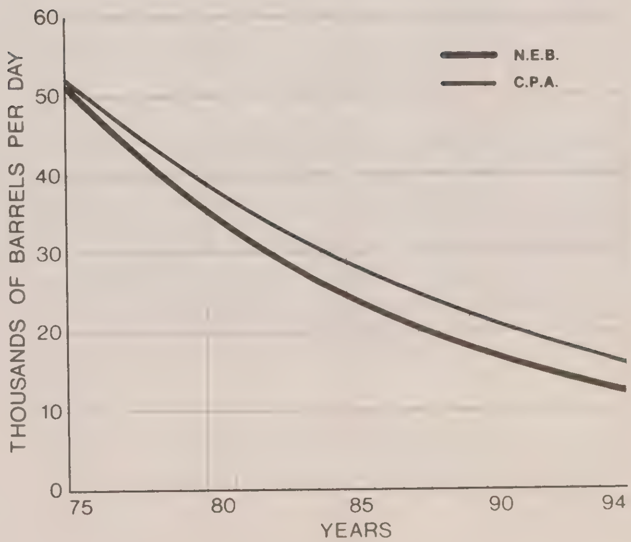


South Saskatchewan Pipe Line Company: *The Board's forecast for the South Saskatchewan Pipeline (Saskatchewan's Area III) is based on detailed consideration of twelve oil producing pools and units reflecting 55 percent of the total indicated producibility for 1975. The "other" category, because of its size, was analyzed in considerably more detail than the "other" category in most pipeline systems.*

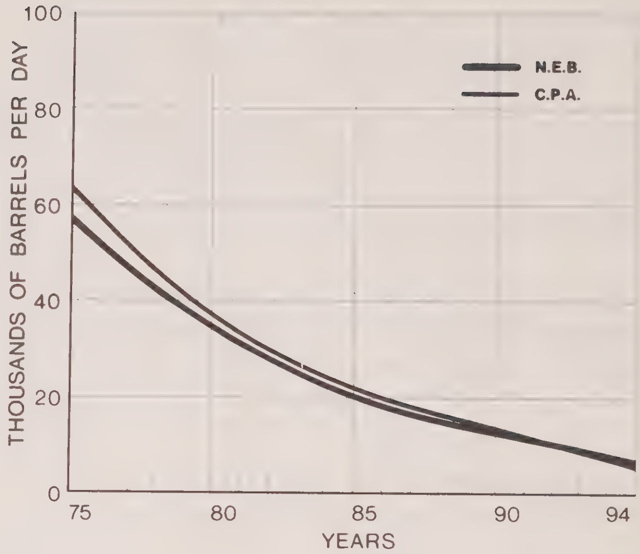
The production gathered by the South Saskatchewan Pipeline is generally declining and the total forecast is in agreement with the data submitted at the hearing.



Westpur Pipe Line Company — Midale Medium: *The Board's potential producibility forecast is slightly below the industry estimate for this pipeline. This is due primarily to the Board estimating lower remaining reserves than industry for Midale Unit (37.9 MMstb vs Shell's 46.5 MMstb), Flat Lake Voluntary Unit No. 1 (6.5 MMstb vs PanCanadian's 9.5 MMstb) and the Lost Horse Hill Frobisher Alida pool (5.1 MMstb vs Imperial's 7.7 MMstb).*

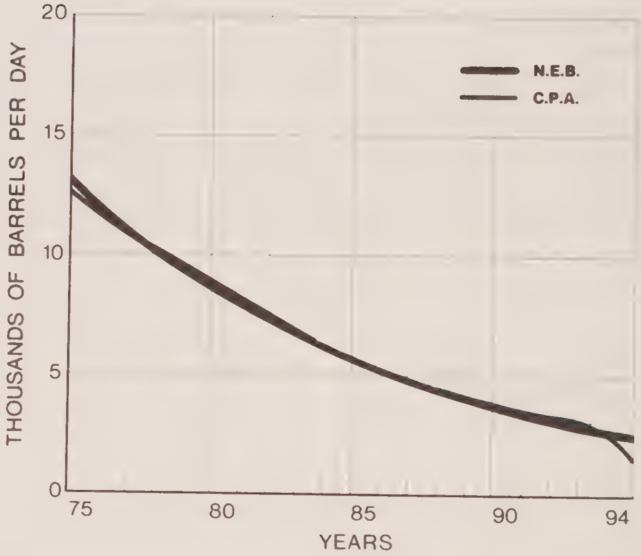


Westpur Pipe Line Company — S.E. Sask. Light: *The crude oil volumes flowing through the Westpur pipeline (light) have decreased more sharply over the past two years than in the years prior to 1972. The Board has used the more recent trend for this pipeline. When examining the individual pool producibilities, considerable weight was given to recent changes in performance. Therefore, the Board's total forecast is slightly lower than the industry estimate shown in the C.P.A.'s submission. In addition, the Board has assigned lower established remaining reserves than industry to the Ingoldsby Frobisher — Alida Beds Voluntary Unit (6.2 MMstb vs Imperial's 7.7 MMstb), Steelman Unit IA (20.1 MMstb vs Imperial's 21.6 MMstb), and Steelman Unit VI (11.8 MMstb vs Gulf Oil Canada Limited's ("Gulf") 16.1 MMstb).*



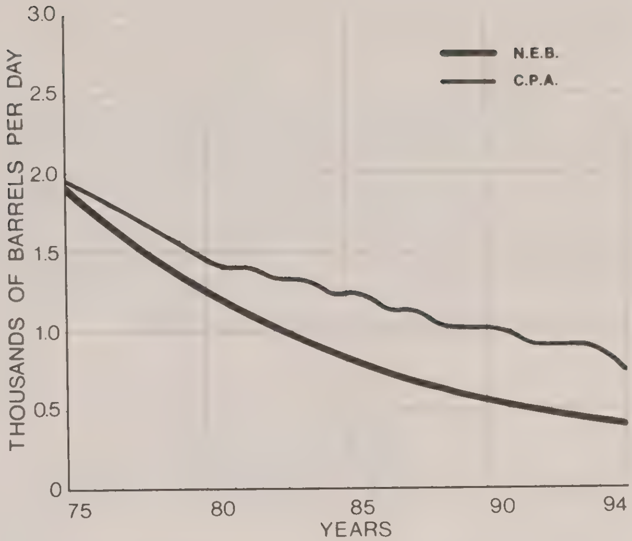
MANITOBA

Trans-Prairie Pipelines Ltd. (Manitoba): *The initial established reserves in the province of Manitoba were approximately two thirds depleted by the end of 1974. The majority of the producing areas are on established patterns of production decline. The Board's forecast reflects these trends and is in agreement with the data submitted by industry.*



ONTARIO

The initial established reserves in the province of Ontario are approximately 87 percent depleted and the Board's calculation of future producibility and reserves was obtained by an extrapolation of historical performance.



TOTAL CANADA

The pipeline producibility forecasts have been summed by province and the provincial contributions to total Canadian oil producibility from established reserves are shown in Figure 4. Potential producibility of oil from each of Manitoba, the Northwest Territories, and Ontario too small to be shown separately. This does not of course imply any judgment as to future discoveries and associated deliverability.

The Board's current forecast of potential producibility from established reserves is compared to the October, 1974 forecast in Figure 5. As can be seen from the graph, there has been little change from last year in the Board's forecast of potential producibility from established reserves. It should be noted that the curves are not completely comparable since the present forecast includes those reserves added since the October, 1974 report was prepared, and which would have been included in the forecast of reserves additions at that time.

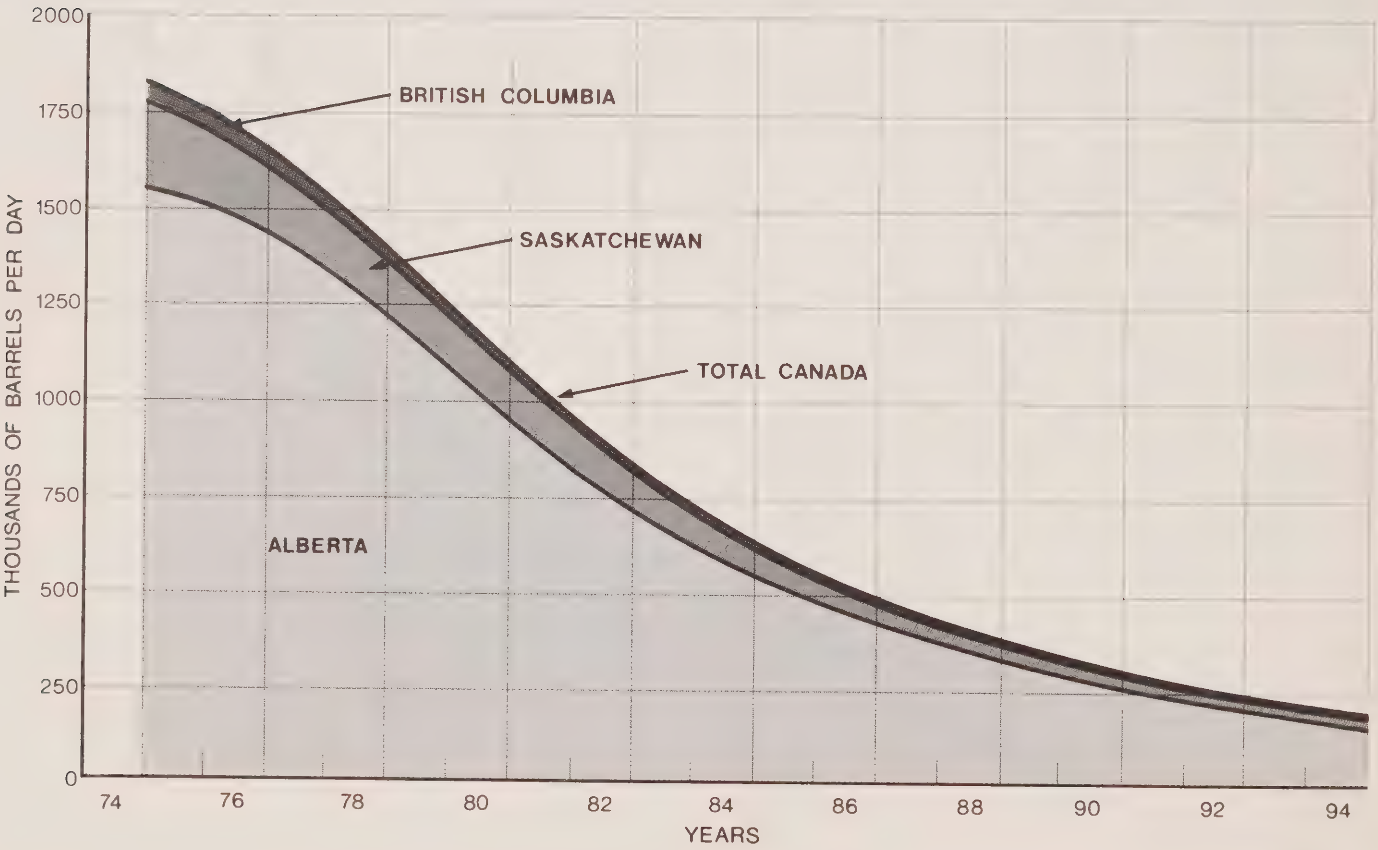


Figure 4: Forecasts of Potential Producibility From Established Reserves By Province.

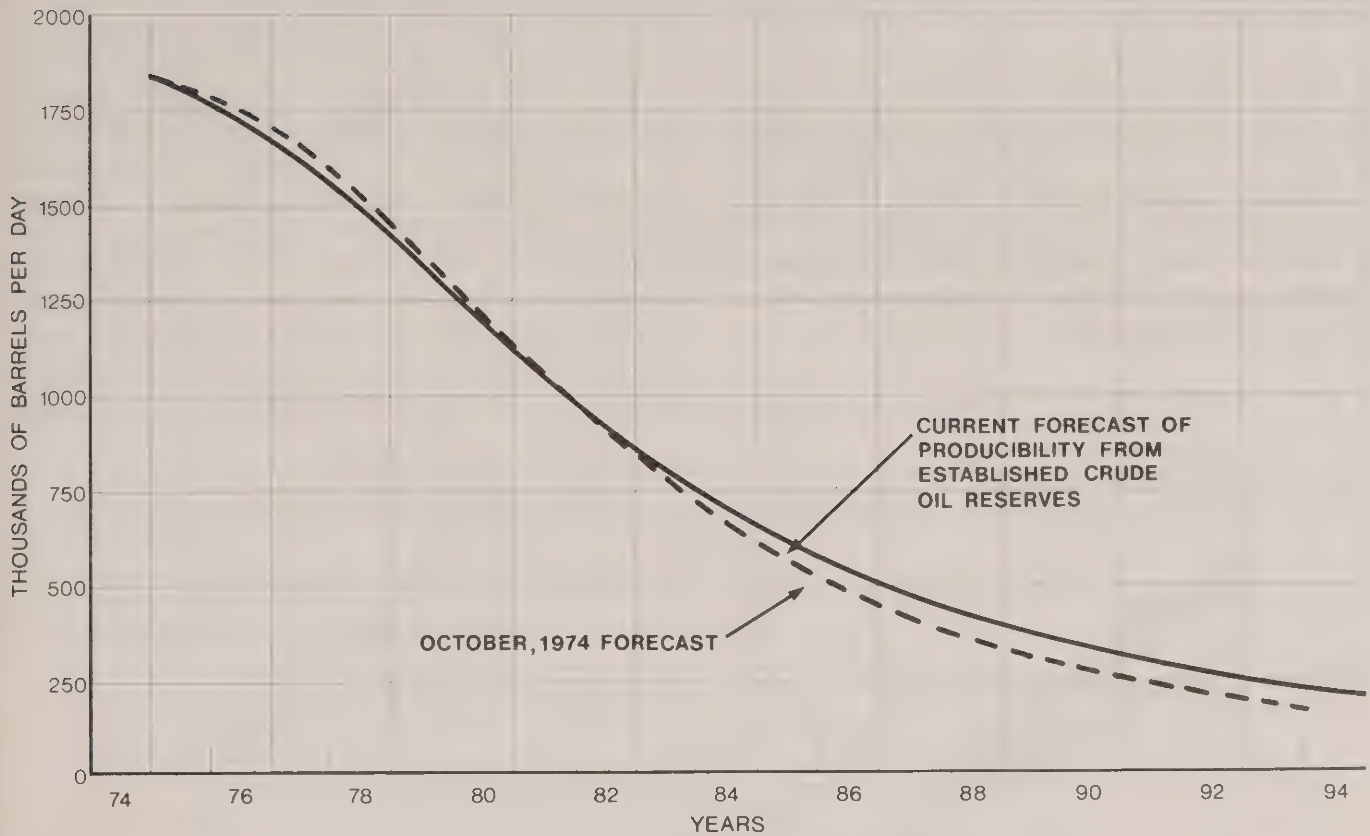


Figure 5: Comparison of October 1974 and current Forecasts of Potential Producibility From Established Reserves.

Additions to Established Reserves in Conventional Areas

i) Views of Submittors

Only Gulf, the B.C. Energy Commission and the AERCB submitted forecasts of annual reserves additions. Several other submittors provided an estimate of cumulative reserves additions over the 20-year forecast period, and some submittors provided forecasts of producibility from reserves additions without attempting to quantify the rate of reserves additions.

Collectively, submittors stressed the difficulty of making any assumptions regarding future exploration and development activity in light of the economic uncertainties being experienced by the industry.

There was a consensus that the majority of future reserves additions in the conventional areas would result from enhanced recovery techniques. Imperial attempted to quantify this potential by listing geological horizons and suitable recovery techniques as a function of crude oil price. Regarding production from tertiary recovery techniques, the witness for Chevron estimated that it would take from 10 to 15 years to move projects from the pilot plant stage to the commercial stage. This estimate was supported by other expert witnesses, although some submittors thought that the pilot plant stage could be eliminated as experience was gained.

ii) Views of the Board

The reserves additions schedules submitted at the hearing are shown in the table below together with the Board's October 1974 estimates. The numbers shown as the Board's estimates were not given by province in the October, 1974 report, but are the values used to calculate the published producibility estimates from reserves additions. They were based on submissions at that hearing, trend extrapolations, and an appreciation for future potential.

The Board has reviewed the information submitted at its hearing and noted the considerably higher reserves additions as forecast by the B.C. Energy Commission and the AERCB. However, based on extrapolation of historical trends and assessment of geological potential, the Board concludes that there is no reason at this time to change its previous forecast of reserves additions. Implicit in adopting the previous estimate is the assumption that industry economics over the forecast period will be consistent with the conditions that prevailed when the historical trends were established. However, a very substantial increase in the price of crude oil or a major technological breakthrough in tertiary recovery techniques could make this forecast conservative.

COMPARISON OF CRUDE OIL RESERVES ADDITIONS FORECASTS FOR THE CONVENTIONAL PRODUCING AREAS IN SOUTHERN CANADA

(MMstb)

	BRITISH COLUMBIA			ALBERTA			SASKATCHEWAN		TOTAL CANADA	
YEAR	GULF	B.C. ENERGY COMMISSION	NEB	GULF	AERCB	NEB	GULF	NEB	GULF	NEB
1975	5.0	1.0	6.6	140	100	128	36	31	181	169
1976	4.0	1.3	5.3	130	200	117	33	27	168	152
1977	3.0	1.6	4.3	123	200	106	30	24	156	137
1978	4.0	1.8	3.5	115	200	97	27	21	147	124
1979	3.0	2.1	2.8	108	200	88	24	19	135	112
1980	4.0	2.3	2.3	102	200	80	22	16	129	102
1981	3.0	2.6	1.9	96	200	73	19	14	118	92
1982	4.0	2.9	1.5	90	200	66	17	13	112	83
1983	2.0	3.1	1.2	85	200	60	16	11	103	75
1984	2.0	3.4	1.0	79	200	55	14	10	95	68
1985	3.0	3.6	0.8	75	200	50	13	9	91	62
1986	2.0	3.9	0.7	70	200	45	10	8	82	56
1987	2.0	4.2	0.5	65	200	41	9	7	76	51
1988	2.0	5.2	0.4	62	200	38	9	6	73	46
1989	3.0	6.2	0.3	58	200	34	8	5	69	42
1990	2.0	6.2	0.3	55	200	31	8	5	65	39
1991	2.0	6.2	0.2	52	200	28	7	4	61	35
1992	2.0	6.2	0.2	48	200	26	6	3	56	32
1993	1.0	6.2	0.2	46	200	23	5	3	52	29
1994	2.0	6.2	0.1	43	200	21	5	3	50	27

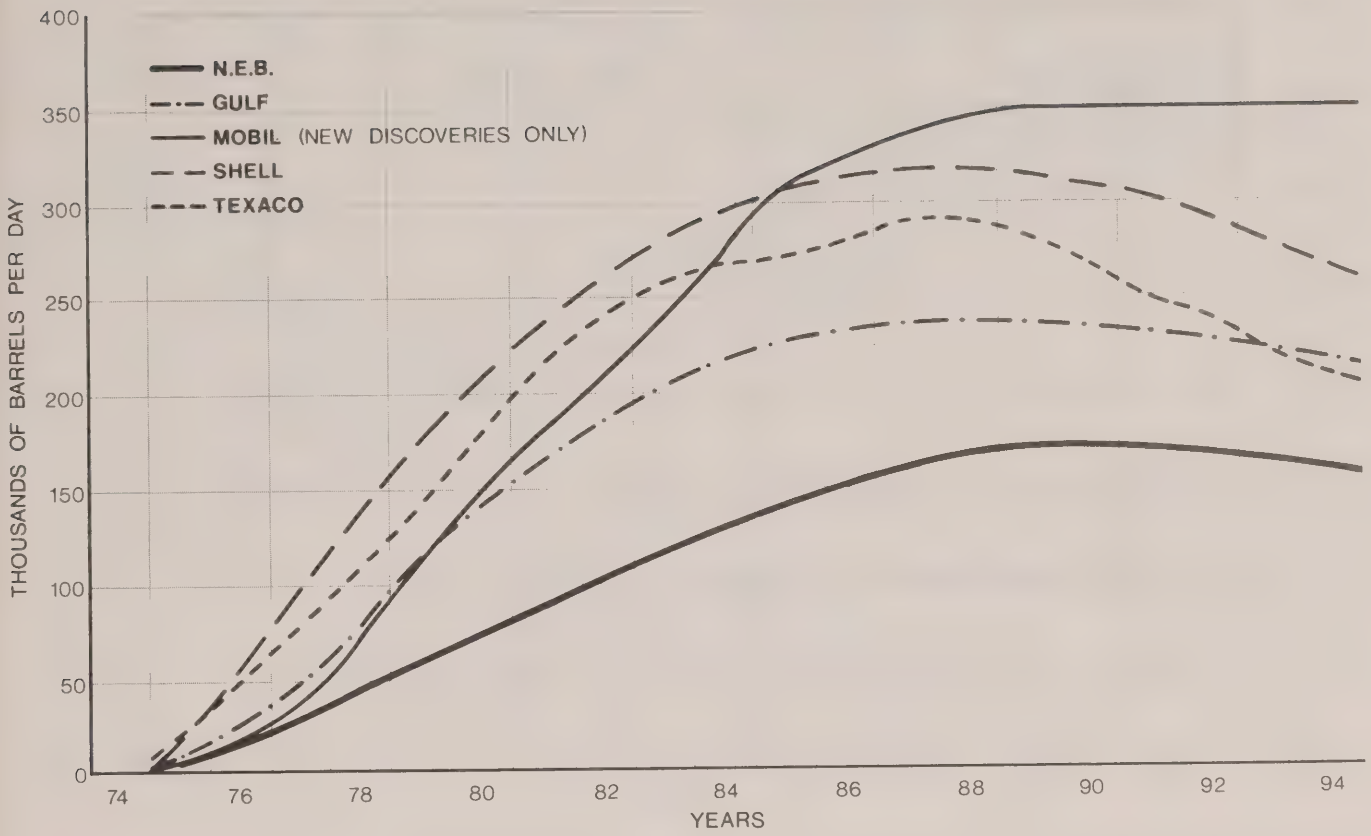


Figure 6: Forecasts of Crude Oil Producibility From Reserve Additions in Conventional Areas.

The Board has noted and generally agrees with the comments relating to lead times for implementation of new tertiary recovery schemes. Accordingly, it envisages that during the next decade the majority of reserves additions will accrue from secondary recovery processes, such as new or expanded waterflood schemes and improvements in waterflooding techniques. Some additions could come from other schemes such as miscible flooding and polymer injection.

The Board believes that reserves additions which arise from enhanced recovery schemes result in lower initial producing rates than similar reserves of new primary oil. To translate annual reserves additions into producibility, an initial reserves to production ratio of 30 has been used, declining ten percent annually to a constant ratio of 10.

The resulting forecast of potential producibility from additions to established reserves in the conventional producing regions in Canada is shown in Figure 6. Also shown are the forecasts submitted at the hearing. The Board's forecast is below the industry estimates. It is somewhat below the estimate shown in the October, 1974 report, primarily because reserves additions for 1973 and 1974 are now included in the established category.

Pentanes Plus Reserves

i) Views of Submittors

The forecasts of pentanes plus producibility submitted at the hearing are shown in Figure 7. HBOG and the AERCB provided details on a pool or plant basis. Other companies provided pentanes plus forecasts for gas pools which they operate. All forecasts shown include pentanes plus production from established natural gas reserves together with production

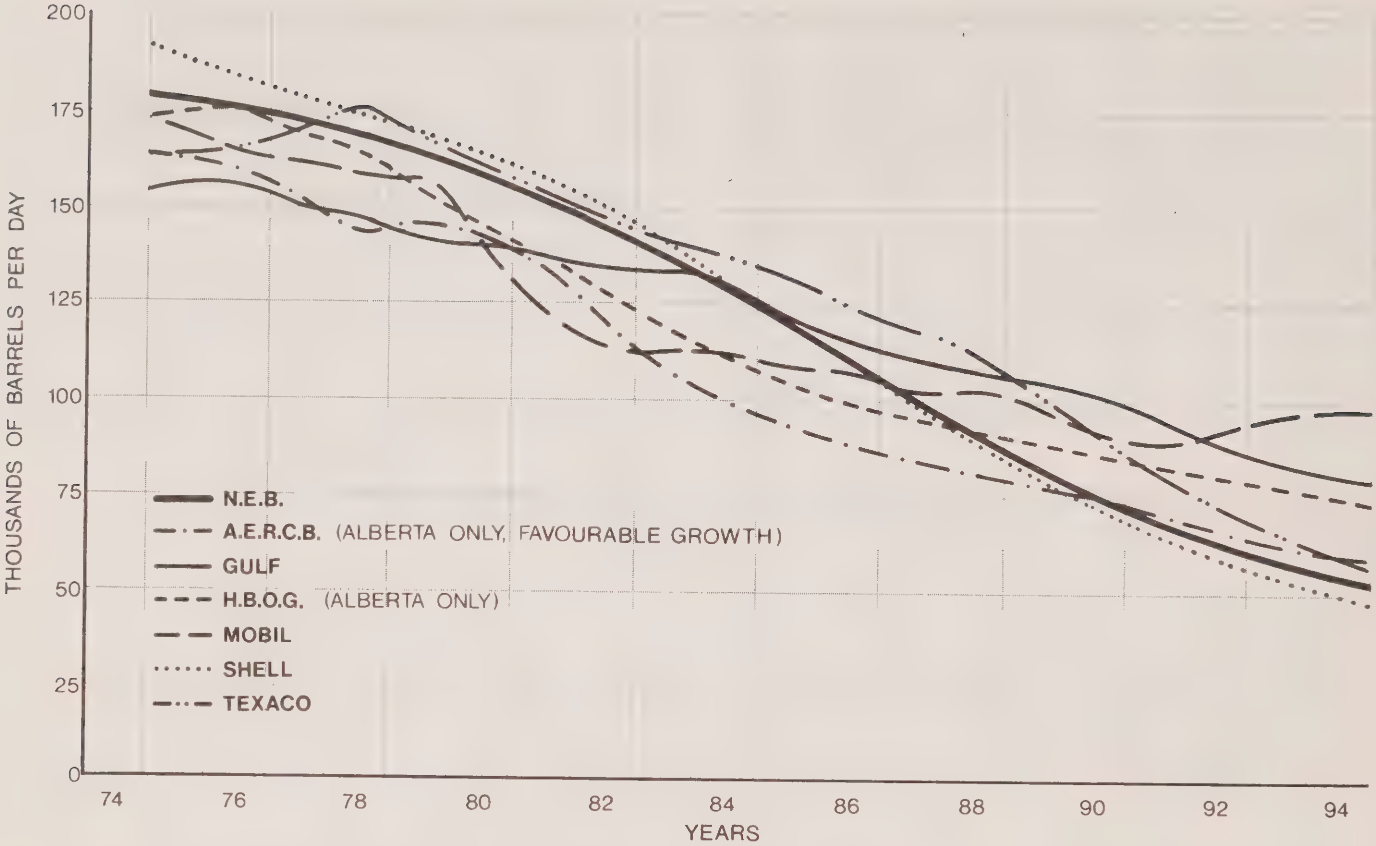


Figure 7: Forecasts of Producibility of Pentanes Plus From Established Reserves and Reserve Additions.

from forecast reserves additions. Assumptions regarding yield of pentanes plus from natural gas reserves additions ranged from 5 to 19 barrels per million cubic feet.

ii) Views of the Board

The pentanes plus forecast used by the Board for the October, 1974 report has also been plotted on Figure 7. The assumptions used to prepare that forecast were discussed in detail in that report. In view of the general agreement of the forecasts shown in Figure 7, the Board has decided to adhere to its 1974 forecast for pentanes plus producibility.

Oil Sands Deposits

i) Views of Submittors

The following table contains a summary of the estimates submitted regarding the commencement of operation of various oil sands mining and in situ plants. In the case of most submittors, this represents a substantial reduction from last year's estimates. The reasons most commonly cited for this were:

– the estimates of construction costs including the effect of inflation have more than doubled,

– the current economic climate related to governments' share of income, (royalties and taxes),

– the problem of finding sufficient risk capital to finance these large projects.

ii) Views of the Board

The difficulties currently being experienced in development of the massive oil sands projects were not totally unanticipated. The Board's forecast of last year was considerably more conservative than other forecasts submitted at that

COMPARISON OF PROJECTED START-UP DATES FOR OIL SANDS PROJECTS

	MINING PLANTS			IN SITU PROJECTS	
	Syncrude	Mining #3	Mining #4	In Situ #1	In Situ #2
1978	AERCB SHELL	–	–	–	–
1979	TEXACO GULF IMPERIAL	–	–	–	–
1980	–	AERCB	–	–	–
1981	–	–	–	–	–
1982	–	SHELL SUN	AERCB	–	–
1983	–	GULF IMPERIAL	–	–	–
1984	–	–	HOME SUN	AERCB	–
1985	–	–	–	SHELL MURPHY IMPERIAL	–
1986	–	–	IMPERIAL	–	–
1987	–	–	GULF	–	–
1988	–	–	SHELL	–	–
1989	–	–	–	–	–
1990	–	–	–	–	–
1991	–	–	–	GULF	SHELL
1992	–	–	–	–	–
1993	–	–	–	–	–
1994	–	–	–	–	–

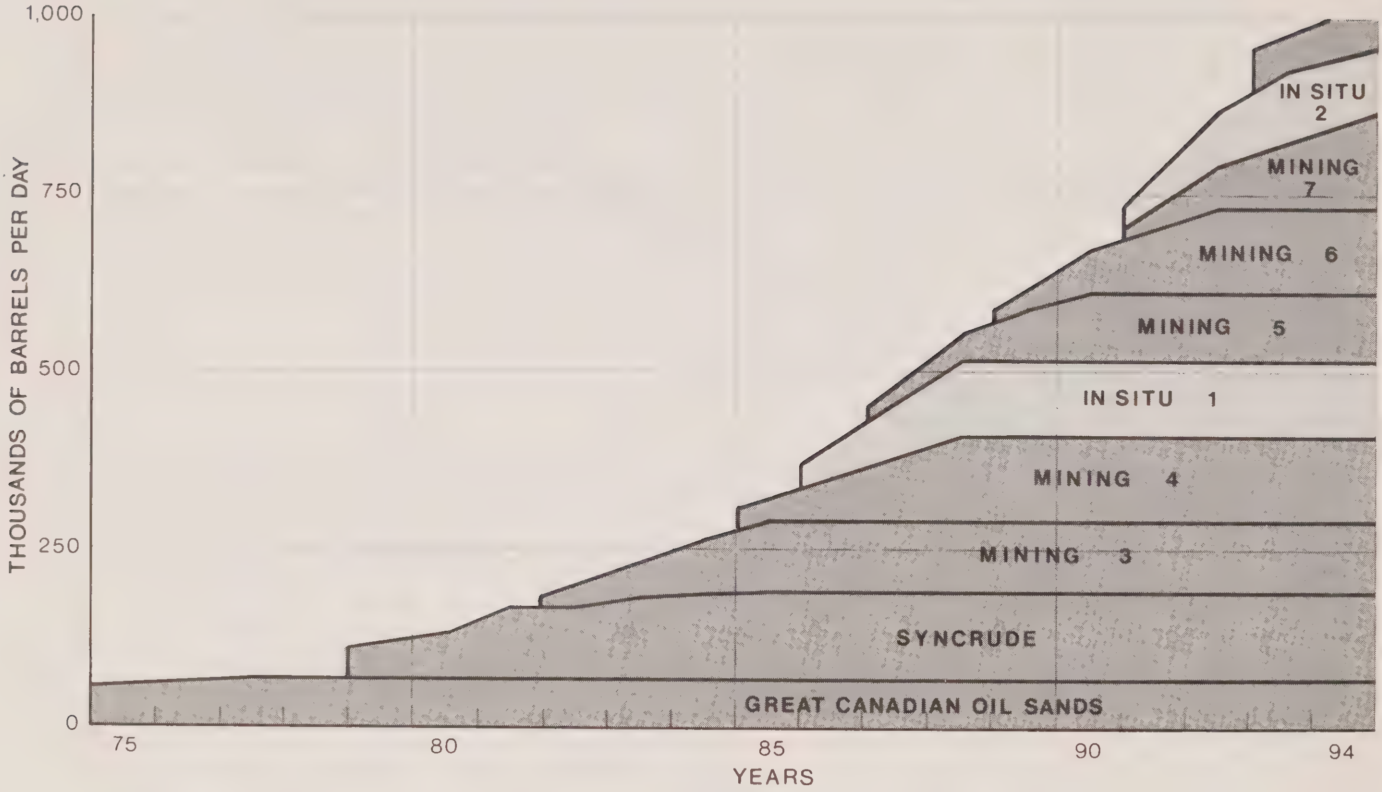


Figure 8: N.E.B. Forecast of Oil Sands Producibility.

time. However, the effects of inflation and the current economic environment have made even the Board's forecast appear optimistic. Consequently, while still expecting production from the Syncrude plant in 1979, the Board is allowing for one year of slippage in the on-stream date for the third mining plant from 1981 to 1982. This would put Syncrude and the next mining plant three years apart. It also appears reasonable to allow three years before the next plant is completed, meaning that the fourth mining plant would commence production in 1985. Developments following this are expected to be heavily influenced by the success of frontier oil exploration efforts. To illustrate what the Board believes is a plausible development rate for mining plants after 1985, plants are shown as coming on stream every two years, in Figure 8.

With regard to in situ oil sands plants, the Board believes that the previous estimate of 1986 for production from the first plant is still realistic, pending suitable economic arrangements between the developer and governments. In the light of evidence presented at the hearing, the on stream date of the second plant has been moved from 1990 to 1991.

Frontier Reserves

i) Views of Submittors

Several companies submitted reserves and producibility estimates for the frontier areas. However, only three companies projected production from these areas prior to 1985, which is the last year covered in the period of protection. In each case the region expected to be on production earliest

is the Mackenzie Delta-Beaufort Sea area. The three estimates are as follows:

Submittor	Year of First Production	Production Rate Mb/d
Imperial	1983	300
Mobil	1983	200
Texaco	1984	100

ii) Views of the Board

It is the opinion of the Board that the estimates presented in the above table are not unreasonable. However, until definitive plans for a pipeline have been established, Arctic producibility must be considered too speculative to warrant inclusion in a procedure designed to provide protection for Canadian requirements. Accordingly, the Board's forecast does not include reserves or potential producibility estimates from the frontier regions.

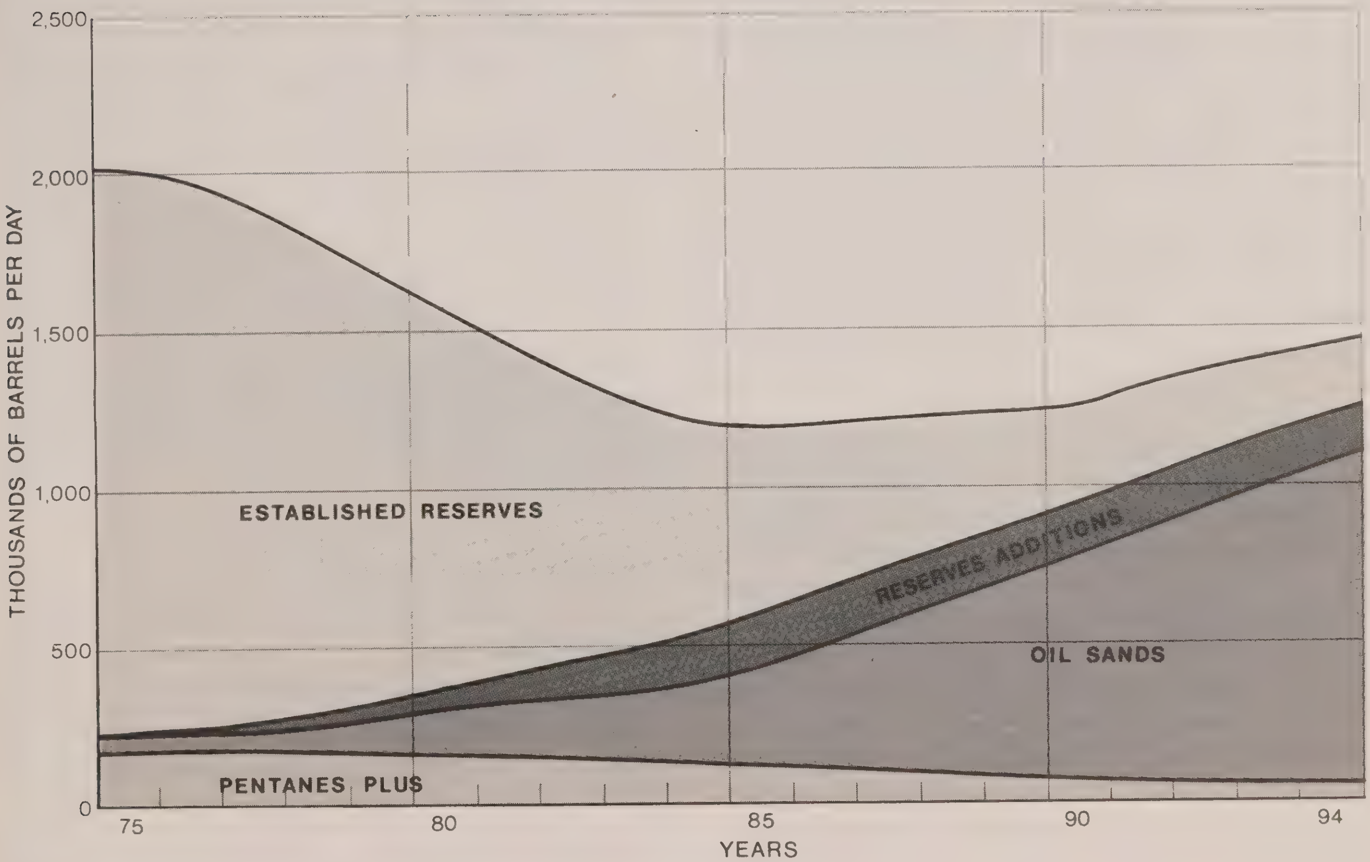


Figure 9: N.E.B. Forecast of Potential Producibility of Canadian Crude Oil and Equivalent.

Requirements and Conservation Considerations

The Demand for Petroleum Products

This section of the report deals with the views of submittors and the views of the Board concerning the future demand for petroleum products in Canada. As set forth in item II of the Outline for Submissions (Appendix B) submittors were requested to provide forecasts of total market sales of refined petroleum products in sufficient detail to permit a comparative evaluation. Submittors were also invited to provide opinions and, if possible, estimates to assist the Board in identifying and quantifying reductions in Canadian oil demand resulting from conservation measures.

Of the thirty submissions received, fifteen contained information on demand. The names of these submittors are shown in Appendix E, Table 1. Of these, thirteen actually provided forecasts. Some of the submittors who provided demand forecasts restricted themselves to the market areas or products with which they were primarily concerned. Four submittors provided forecasts of demand for all the major refined petroleum products for all the major regions in Canada. Of these, two submittors provided forecasts which incorporated anticipated or potential effects of specific conservation measures on demand.

The Board has considered the evidence submitted at this hearing, and has developed two sets of forecasts of demand for petroleum products in Canada: demand in the absence of energy conservation and demand considering conservation effects. A regional breakdown of the forecasts developed by the Board is tabulated in Appendix E, Tables 2 through 13. For the case of demand with conservation, a product by product breakdown is provided for each region. For the case of demand without conservation, the Board's forecast of the total demand for all products in each major region is presented. A summary comparison of the various forecasts of total petroleum product demand in Canada, 1974-1994, is presented graphically in Figure 10. It should be noted that in all cases where the range of submission estimates is given, neither the high nor the low forecasts are necessarily comprised of the figures of any one submittor. Further, where submittors did not provide estimates for particular years, as requested in the Outline for Submissions, Board staff made the necessary interpolations or extrapolations.

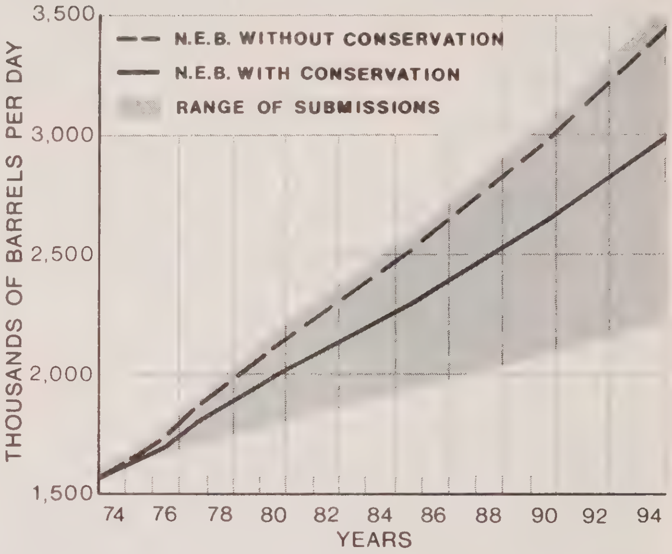


Figure 10: Comparison of Total Petroleum Product Demand, Canada, 1974-1994.

The views of submittors and the Board related to major forecast assumptions, energy conservation, and factors concerning specific forecasts of the major petroleum products are presented in the following sections.

a) Major Forecast Assumptions

i) Views of Submittors

Submittors were requested to describe clearly their major assumptions, especially those concerning the relative prices of oil and other energy forms in various markets. In summary, the following views were expressed.

The assumptions made by submittors regarding the rate of growth of real Gross National Product ("GNP") in Canada over the forecast period were similar. Imperial and Texaco Canada Limited ("Texaco") both assumed an average annual growth rate in GNP of 4.5 percent between 1974 and 1994. Shell assumed no economic growth in 1975, and an annual rate of growth of 5.0 percent between 1976 and 1994.

As with GNP, the assumptions made by submittors regarding the rate of growth of population in Canada over the forecast period were generally quite similar. Shell assumed an annual rate of growth of 1.2 percent, Imperial assumed 1.3 percent, and Texaco assumed 1.4 percent.

The demand forecasts provided by submittors were usually based on the assumption that the Canadian crude oil prices (and therefore the prices of petroleum products) would rise toward world prices. Gulf assumed that Canadian crude oil prices would reach world prices by 1977; Imperial assumed 1978, while both Shell and Texaco assumed 1980. Submittors did not make explicit assumptions about the movement of crude oil prices beyond 1980.

Most submittors assumed that the prices of natural gas and oil would move towards equivalence on a British thermal unit ("Btu") basis. In its base case (no conservation) Shell assumed that natural gas would remain underpriced relative to oil, while in its conservation case Shell assumed Btu equivalence would be reached in 1977. Texaco assumed that natural gas prices would increase to the point where the cost to the consumer would be equivalent to refined petroleum products on a Btu basis, but gave no date for this to occur. Texaco indicated that the assumption of Btu price equivalence of oil and gas in Ontario and Quebec would imply that natural gas would still be the more economical fuel in the Prairie Provinces.

The B.C. Energy Commission, in forecasting the demand for petroleum products in British Columbia, assumed a gas price sufficiently below oil in the residential sector to capture most of the incremental market in gas-serviced areas. In the commercial and industrial sectors, it used two price assumptions to develop two different forecasts. The first assumption was the same as that used in the residential sector, (that is, gas priced lower than oil), while in the second case prices would be such that consumers would be indifferent between the use of oil and gas.

Imperial assumed that electricity prices would increase, but at a slower rate than those for oil and gas, as new coal and nuclear generating facilities increasingly supplement traditional sources.

In general, submittors assumed no significant expansions of natural gas service areas, either in the province of Quebec (to areas east of Montreal) or in British Columbia (to Vancouver Island). The B.C. Energy Commission and Standard Oil Company of British Columbia Limited specifically assumed that no extension of gas service to Vancouver Island would occur during the forecast period. Shell assumed no extension of the gas service areas in either British Columbia or Quebec. Texaco and Gulf stated that they did not assume a major increase in the share of natural gas in the Quebec market.

ii) Views of the Board

The following major assumptions underlie the various petroleum product demand forecasts prepared by the Board.

It was assumed that there would be little or no growth in Canada's real GNP in 1975, followed by some expansion in 1976, and an average annual growth rate of 4.5 percent between 1977 and 1994. It was also assumed that Canada's population would grow at an annual rate of 1.3 percent over the forecast period. This assumption is consistent with Statistics Canada Projection B in "Population Projections for Canada and the Provinces 1972-2001."

Regarding prices, it was assumed that the Canadian crude oil price would approach the world price of crude by the end of the decade. It was also assumed that the price of natural gas at the city gate in Toronto would equal the price of crude oil at the refinery gate in Toronto by 1978, on a Btu equivalent basis. This assumption implies that the cost of natural gas at the city gate in Northern Ontario, Manitoba, Saskatchewan and Alberta will be less than the equivalent cost of crude oil, since the cost of transporting gas is greater than the cost of transporting oil. Further, it was assumed that price equivalence on a Btu basis at the city and refinery gates in Toronto would result in relative prices on a Btu basis at the burner tip in the residential/commercial sectors such that natural gas will be the slightly preferred fuel in these sectors because of its premium qualities. In the industrial sector, it was assumed that price equivalence on a Btu basis at the city and refinery gates would result in burner tip prices such that, in general, the final consumer would be indifferent as to whether natural gas or oil is used as a fuel.

It was assumed for the purposes of this forecast that there will be no expansion of the gas service area in the province of Quebec and no extension to Vancouver Island, over the forecast period. It should be noted that these assumptions may not be consistent with views expressed at other hearings of the Board or with the Board's views expressed in previous reports. In the recent NEB Natural Gas Supply and Requirements Report, for example, it was assumed that gas service would be extended to these areas. The assumptions made in the present report reflect the evidence and Board judgments on the matter at this time. If there is any resulting bias in the petroleum product demand forecasts, it is in the direction of providing additional protection for Canadian requirements.

Regarding each form of energy, it was recognized that there may be supply constraints from time to time during the forecast period, but these are not possible to predict with precision and for the purpose of this forecast, it was assumed that there would be none.

b) Conservation

i) Views of Submittors

An important purpose of the hearing was to obtain a cross-section of views on conservation as it relates to the consumption of petroleum products in Canada. The views provided by submittors demonstrated that the problem of defining conservation is as intricate as the problem of estimating its probable impact on future demand.

It was generally agreed that both higher crude oil prices and government sponsored conservation programs would lead to a dampening of future Canadian demand for refined petroleum products. There was no agreement, however, as to whether or not demand reductions due to higher prices should be termed "conservation".

Imperial was explicit both in its submission and in subsequent testimony in stating that the definition of conservation should be restricted to cover only the amount of demand reduction brought about by non-price factors. In its submission, Imperial provided three forecasts: a Trends Continued case, and Case A and Case B which depicted, respectively, a moderate and a severe response to higher energy prices and/or government demand-reducing programs. It was therefore possible to determine how much higher energy prices and government programs taken together would reduce demand relative to its Trends Continued case, but it was not possible to determine how much of the reduction would be due to price change and how much due to government demand-reducing programs.

Gulf did not attempt to measure the effect of conservation on demand. It did, however, define conservation to include price effects. Gulf recommended conservation through legislation where necessary and through economic policies designed to permit energy prices to reach competitive levels in the market place.

Several submittors provided estimates of the effect of conservation on demand. Most submittors addressing themselves to this subject provided estimates of total energy savings in each of the major end-use sectors that could result from conservation.

In the transportation sector, the energy consumed consists mostly of motor gasoline and diesel fuel. In turn, very little of these refined petroleum products are consumed in any other sector. Imperial estimated that higher energy prices and/or government demand-reducing programs could lead to a reduction in the demand for energy in the transportation sector from 15 percent (Case A) to 28 percent (Case B) by 1990, relative to its Trends Continued case. Imperial noted that such reductions could come about from the development of smaller automobiles and automobile engines, reduced use of automobiles, reduced speed, and the encouragement of less energy-intensive transportation modes (such as rapid transit). The Nova Scotia Energy Council ("N.S. Energy Council"), after examining various potential areas of demand reduction in the transportation sector, projected a maximum reduction of 11.4 percent in motor gasoline consumption in Nova Scotia by 1994, and no reduction in diesel fuel consumption, relative to its "no conservation" case. Shell estimated a possible total demand reduction in the transportation sector due to conservation of 13 percent by 1980 and 23 percent by 1990, relative to its base case. The Ontario Ministry of Energy ("Ontario") submission contained a detailed analysis of the reductions in demand which were possible in the transportation sector from conservation measures. Preliminary indications suggest motor gasoline demand could be reduced by at least 20 percent and possibly

as much as 30 percent by 1994 relative to historic trends, and that savings in the order of 10 percent for diesel fuel could be realized. In the Ontario submission, consumption in the transportation sector was discussed as being a function of the number of vehicles, the degree of utilization of the vehicles, and the efficiency of the vehicles. The number of vehicles is determined by population and income, while the degree of utilization is determined by necessity, convenience and the availability of transportation choices. It was suggested that the convenience, comfort and privacy of the automobile will not be easily discouraged and therefore a severe increase in the cost/benefit ratio of private cars would be required in order to change utilization patterns. In the area of potential savings from increased vehicle efficiency, Ontario discussed vehicle size mix, aerodynamic drag, engine type (primarily the advantages of diesel over gasoline engines and the possibilities of the stratified charge engine), maintenance and driving habits. The possibilities of intermodal shifts in commercial transportation (such as piggyback and containerization) and the electrification of major rail lines were mentioned as areas for potential saving of diesel fuel.

Light fuel oils are consumed primarily in the residential/commercial sector and it is in this sector that most of the light fuel oil conservation would occur. In the Ontario submission it was concluded that the various feasibilities of conservation could lead to a potential demand reduction of 15 to 20 percent by 1994 in the residential sector and 15 to 20 percent in the commercial sector. Imperial estimated that energy price increases and/or government demand-reducing programs would reduce demand in the residential/commercial sector by 10 percent (Case A) to 22 percent (Case B) by 1990, relative to its Trends Continued case. Shell estimated potential demand reductions in the residential/commercial sector through conservation of 18 percent in 1980 and 22 percent in 1990 relative to its base case. In arriving at these estimates, Shell assumed that, beginning in 1976, the National Building Code would be amended so that insulation of all new houses would conform to standards for electrically heated homes. It was also assumed that 50 percent of the existing stock of houses would have extra insulation added by 1980, and 80 percent would have extra insulation by 1990. Improved furnace efficiency (more efficient burners and heat exchangers, recycled effluent gases, and insulated ductwork) as well as increased public awareness were also considered. In commercial buildings, savings were anticipated from improved heating and cooling technology and improvements in architectural design.

Heavy fuel oil is consumed primarily in the industrial and commercial sectors. Shell estimated potential savings from conservation in the industrial sector of 10 percent by 1980 and 36 percent by 1990 relative to its base case. Such savings could result from incentives to increase capital investment in equipment and processes which use energy more efficiently, more-frequent maintenance, replacement of inefficient equipment and the recycling and re-use of component materials. Imperial estimated that energy price increases and/or government demand-reducing programs could reduce demand in the industrial sector by 10 percent (Case A) to 17 percent (Case B) by 1990, relative to its Trends Continued case. The mechanisms through which such savings might occur were similar to those outlined by Shell.

ii) Views of the Board

As noted earlier, the Board prepared two sets of forecasts of the demand for refined petroleum products in Canada. The differences between these two sets of forecasts reflect the Board's estimates of the effect of conservation on the demand for the various petroleum products. These estimates reflect the Board's view that the results of all efforts made by Canadians to reduce the use of petroleum products should be recognized as conservation. This should be the case whether, for example, people turn down their thermostats as a result of increases in the price of light fuel oil, or whether demand is reduced in response to a specific government-sponsored conservation program. On the other hand, it is felt that decreases in the demand for petroleum products due to the substitution of other forms of energy could not be classified as conservation.

In Appendix E Table 14, the Board's estimates of the effect of conservation on the demand for energy are provided. These estimates support the Board's forecasts of petroleum product demand. For each major end-use sector, a description is provided of the possible conservation actions that might be taken, the motivating forces behind such actions, and the resulting energy savings. For the transportation sector, total energy savings of approximately 17 percent due to conservation are envisaged by 1994; for the residential/commercial sector, 15 percent; and, for the industrial sector, 15 percent.

c) Forecasts of Refined Petroleum Product Sales

As outlined in item II of the Outline for Submissions (Appendix B), submittors were requested to provide estimates of total market sales of motor gasoline, light fuel oil, kerosene and stove oil, diesel fuel, heavy fuel oil, petrochemical feedstock, and other products. It was suggested that estimates be provided for the Atlantic Provinces, Quebec, Ontario, Manitoba, Saskatchewan, Alberta, British Columbia and the Yukon and Northwest Territories, and for the years 1975, 1976, 1977, 1980, 1985, 1990 and 1994. It was also suggested that all forecasts be accompanied by one year or more of actual data.

Forecasting the demand for refined petroleum products in Canada over the next 20 years is a complex task. The prices of all energy forms are changing substantially, both absolutely and relatively. Demand conservation is a relatively new phenomenon, and there is very little historical experience to assist in identifying and estimating its impact on future demand. Given the uncertainties, there is substantial scope for divergent opinion.

Motor Gasoline

i) Views of Submittors

Submittors provided a rather wide range of forecasts of the demand for motor gasoline in Canada, largely as a result of the different assumptions employed by each. There was general agreement, however, that motor gasoline demand would not continue to grow at historical rates.

Texaco, which did not incorporate the impact of specific conservation measures into its forecast, provided the highest estimate of motor gasoline demand in 1994, at 1,304 thousand barrels per day ("Mb/d"), implying an average annual growth rate of 4.2 percent over the forecast period. The Texaco estimates for motor gasoline sales in the various geographic areas were also consistently higher than those of other submittors (except for the Yukon and Northwest Territories where the Texaco estimate was below that of Shell's base case).

Gulf estimated that total motor gasoline sales would be 1,075 Mb/d in 1994, implying an average annual growth rate of 3.2 percent. In making its estimate, Gulf assumed that technology in the transportation sector would be improved, but not changed radically over the forecast period. Thus, the gasoline piston engine would remain the primary power plant through 1985 with the stratified charge version being phased in after 1977. It was also assumed that fuel economy would continue to be emphasized in automotive design.

Shell provided two forecasts of the demand for motor gasoline in Canada: a no-conservation forecast and a conservation forecast. The conservation forecast constituted the lowest forecast of demand provided by submittors, with estimated demand in 1994 of 651 Mb/d, implying an average annual growth rate of 0.6 percent. Shell's conservation forecast was based on the assumptions that miles driven per car would not increase, that the car sales mix would change from 44/22/34 (standard, compact and sub-compact) to 5/25/70 over the forecast period, and that engine efficiency (in miles per gallon) would increase by 30 percent for sub-compacts and 40 percent for other sizes (relative to the 1974 level of efficiency).

ii) Views of the Board

The Board estimates that if there were no conservation in the use of motor gasoline over the forecast period, demand in Canada would be 1,150 Mb/d in 1994. This would imply an average annual growth rate in demand of 3.6 percent between 1974 and 1994, with regional variations ranging from a low of 2.4 percent in Saskatchewan to a high of 4.9 percent in the Yukon and Northwest Territories, with Ontario, Quebec and the Atlantic region all at 3.6 percent.

Incorporating the anticipated effects of conservation into its forecast, the Board estimates that the total demand for motor gasoline in 1994 will be 922 Mb/d, implying an average annual growth rate of 2.5 percent. Further, it is anticipated that the average annual growth rates in the demand for motor gasoline in the various regions will range from a low of 1.3 percent in Saskatchewan to a high of 3.7 percent in the Yukon and Northwest Territories, with Ontario, Quebec and the Atlantic region at 2.5 percent.

The major factors underlying the Board's forecasts of demand with conservation include expectations that the ratio of automobiles to population will increase from its current level,

engine efficiencies will increase substantially, the new car sales mix will shift significantly to smaller cars and car utilization will not change from current levels. All factors considered, it is estimated that the demand for motor gasoline in Canada will be approximately 20 percent lower by 1994 than it would have been without conservation.

Figure 11 shows a comparison of the Board's forecasts of motor gasoline demand in Canada over the next 20 years, with the range of the high and low forecasts of submittors.

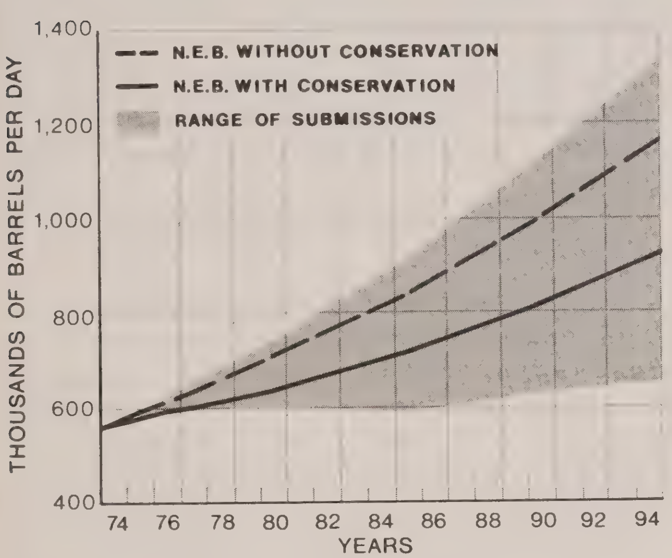


Figure 11: Comparison of Motor Gasoline Demand, Canada, 1974-1994.

Light Fuel Oil, Kerosene and Stove Oil

i) Views of Submittors

Although submittors provided a rather wide range of forecasts of light fuel oil, kerosene and stove oil demand in Canada, there was general agreement that the demand for these products would not grow as rapidly over the forecast period as the demand for other refined petroleum products.

Gulf, Shell (in its base, or no conservation, case), and Texaco were close together in their estimates of total Canadian demand for these products, with forecast sales of 529 Mb/d, 549 Mb/d and 503 Mb/d respectively in 1994. The Shell conservation case and the Imperial Case A (moderate response to higher energy prices and/or government demand-reducing programs) estimates were similar, with forecast sales of 339 Mb/d and 347 Mb/d respectively in 1990.

Most light fuel oil is used in the residential/commercial sector, for space heating. Imperial projected significant penetration by electricity for space heating in the residential/commercial sector in British Columbia, Ontario and Quebec over the forecast period. This projection is reflected in Imperial's forecast of the demand for light fuel oil, kerosene and stove oil in Canada, which implies an average annual rate of growth of 0.5 percent between 1974 and 1990.

The B.C. Energy Commission, dealing specifically with British Columbia's light fuel oil requirements, pointed out that it expects natural gas to capture most of the incremental residential market, with natural gas continuing to be priced lower than light fuel oil. In testimony the B.C. Energy Commission stated that most of the oil-to-gas conversions in the gas-serviced areas in the province have already been made so that this factor will not be important over the forecast period.

ii) Views of the Board

In its forecast of the demand for light fuel oil, kerosene and stove oil, not including the effect of conservation, the Board estimates total demand in Canada at 465 Mb/d in 1994, implying an average annual growth rate of 1.7 percent over the forecast period. In general, for those regions where natural gas is available, it is assumed that it will capture significant portions of the incremental demand for energy in the residential/commercial sector. (This follows from the Board's relative price assumptions discussed earlier under "Major Forecast Assumptions"). It is also expected that electricity will capture a significant portion of the incremental residential/commercial market, especially in those areas where significant amounts of electricity can be generated without use of fossil fuels.

Regarding the Board's regional forecasts of the demand for light fuel oil, kerosene and stove oil, in the absence of the effect of conservation, the average annual growth rates implicit in these forecasts range from a low of zero growth in the Prairie Provinces, to relatively slow growth in Ontario,

British Columbia and Quebec (1.0 percent, 1.3 percent, and 1.7 percent, respectively) to relatively brisk growth in the Atlantic Provinces and the Yukon and Northwest Territories (3.3 percent and 3.7 percent, respectively).

With respect to the Board's forecast of demand with conservation, it is estimated that the impact of conservation will gradually increase to a point where the demand for light fuel oil, kerosene and stove oil will be 15 percent less than it would have been without conservation, by 1994. A significant proportion of this saving is expected to come about through improved insulation of existing and new family dwellings.

Figure 12 shows a comparison of the Board's forecasts of light fuel oil, kerosene and stove oil demand in Canada over the next 20 years with the range of the high and low forecasts of submittors.

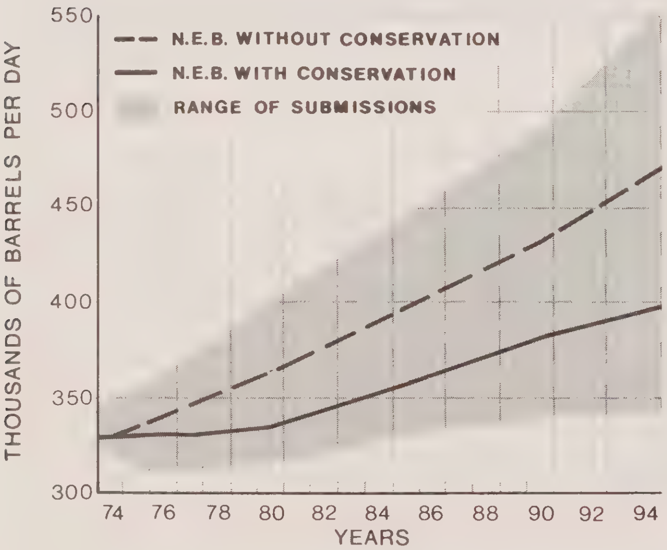


Figure 12: Comparison of Light Fuel Oil, Kerosene, Stove Oil Demand, Canada, 1974-1994.

Diesel Fuel Oil

i) Views of Submittors

Although the forecasts of diesel fuel demand in Canada provided by submittors were based on different sets of assumptions, they were similar. In general, they indicate a common expectation that diesel fuel will continue to show strong growth (relative to most of the other refined petroleum products), although at rates somewhat reduced from historical values, largely because of assumptions of lower levels of economic growth than experienced in the past.

Shell (in its base case) and Texaco (which did not incorporate the effects of specific conservation measures into its forecast) had the highest estimates of diesel fuel sales in 1994, at 486 Mb/d and 489 Mb/d respectively. Shell, in its conservation case, estimated a Canadian demand of 402 Mb/d in 1994. The major factors influencing the Shell conservation case estimates were intermodal shifts from road to rail and some railroad electrification. Imperial provided the lowest forecast of diesel fuel demand, with estimated sales in 1990 of 315 Mb/d in its Case A forecast (moderate response to higher energy prices and/or government demand reducing programs).

ii) Views of the Board

The Board estimates that if there were no conservation in the use of diesel fuel over the forecast period, demand in Canada would be 486 Mb/d in 1994, implying an average annual growth rate of 4.9 percent over the forecast period. Regarding the various regions, for the case of demand without conservation, it is estimated that demand would grow at an average annual rate of 5.2 percent in Ontario, Quebec and British Columbia, and 4.7 percent in the Atlantic region.

With respect to demand with conservation, it is the Board's judgment that although the demand for diesel fuel can be reduced by conservation measures, the scope for such saving is limited. Specifically, it is felt that the prospects of improvements in engine efficiency (as measured by miles per gallon) are not as great for diesel engines as for gasoline engines. Although railway electrification could yield some savings, costs render major conversions unlikely. In addition, significant intermodal shifts from road to rail are not expected. All factors considered, it is estimated that the demand for diesel fuel in Canada will be approximately 10 percent lower by 1994 than it would have been without conservation.

Figure 13 shows a comparison of the range of the high and low forecasts of the submittors and the Board's forecasts of the demand for diesel fuel in Canada from 1974 to 1994.

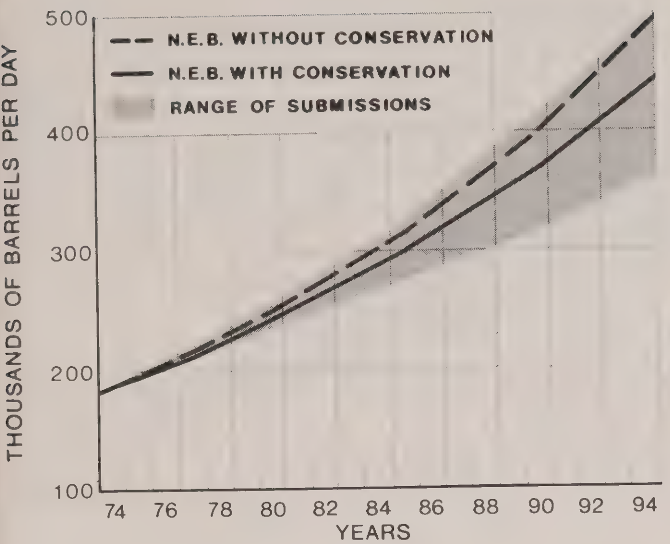


Figure 13: Comparison of Diesel Fuel Oil Demand, Canada, 1974-1994.

Heavy Fuel Oil

i) Views of Submittors

A rather wide range of forecasts of heavy fuel oil demand in Canada was provided by various submittors, again largely reflecting the different assumptions and methodology used. Gulf's forecast was generally the highest, with forecast sales of 692 Mb/d in 1994. Gulf stated that its relatively high forecast (an average annual growth rate of 4.2 percent over the forecast period) primarily reflected Gulf's estimates of heavy fuel oil requirements for thermal generation of electricity. In its testimony, Gulf named the Lennox and Wesleyville generating plants in Ontario and the Coleson's Cove generating plant in New Brunswick as the only new thermal generating plants considered in its forecast.

Shell, in its base case, forecast heavy fuel oil sales between those of Gulf and Texaco until 1980, but forecast a significant decrease in the growth rate of demand after 1980, resulting in a demand of 522 Mb/d in 1994. Shell obtained its estimates of energy requirements in the industrial sector (a major user of heavy fuel oil) by correlating requirements with industrial output and industrial employment and then disaggregating energy demand into demand for specific petroleum products on the basis of interfuel price competition. Regarding heavy fuel oil requirements for thermal generation, Shell specifically considered the same generating plants as Gulf. Shell's conservation forecast generally constituted the lowest forecast of heavy fuel oil demand provided by the submittors. Shell estimated that by 1994, through conservation, the demand for heavy fuel oil in Canada would be approximately 29 percent lower than it would otherwise be.

ii) Views of the Board

The Board estimates that if there were no conservation in the use of heavy fuel oil over the forecast period, demand in Canada in 1994 would be 627 Mb/d. In forecasting the demand for heavy fuel oil in the various regions in Canada, separate examinations were conducted regarding the industrial and commercial end-use sectors, for thermal generation of electricity and the marine transportation subsector.

The Board estimates that there will be little or no growth in the demand for heavy fuel oil in the industrial and commercial sectors through 1977 in those regions where natural gas is available. After that time, it is felt that the demand in these sectors generally will grow at a rate reflecting the rate of growth in real GNP. The exception is in the Prairie Provinces, where it is felt there will be no growth in the demand for heavy fuel oil in the industrial and commercial sectors throughout the forecast period. (These assumptions follow from the Board's relative price assumptions discussed under "Major Forecast Assumptions").

Regarding future demand for heavy fuel oil to generate electricity in Canada, regional forecasts were made by the Board on the basis of current power utility projections of their future generation expansion programs. One of the main considerations was the extent to which the companies currently anticipate meeting future electricity demand with nuclear generating facilities. It is anticipated that most of Canada's future heavy fuel oil requirement for electric power generation will be in the Atlantic Provinces and Ontario. The Board's projections of future heavy fuel oil requirements for power generation in Nova Scotia and Ontario are generally consistent with those outlined in the submissions provided

by the N.S. Energy Council and Ontario Hydro, respectively. Some of the major plants which were considered in estimating Canada's future requirements of heavy fuel oil for power generation were the Coleson's Cove plant in New Brunswick and the Lennox and Wesleyville plants in Ontario.

In the case of demand with conservation, the Board estimates that the demand for heavy fuel oil in Canada will be approximately 12 percent less by 1994 than it would be were there no conservation. It is felt that there is very little scope for fuel conservation either by electric utility companies, or in the marine transportation subsector. Most of the saving in heavy fuel oil is expected to be in the industrial and commercial sectors.

In Figure 14 a comparison of heavy fuel oil demand forecasts between 1974 and 1994 is shown.

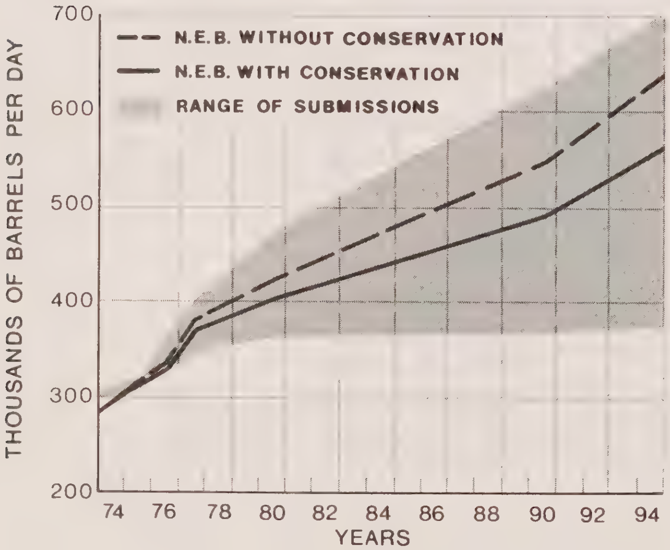


Figure 14: Comparison of Heavy Fuel Oil Demand, Canada, 1974-1994.

Petrochemical Feedstock

i) Views of Submittors

Submittors' estimates of Canadian petrochemical feedstock requirements in 1994 ranged from a high of 198 Mb/d (Shell) to a low of 123 Mb/d (Texaco). The technique used by most submittors was to assume a constant annual rate of growth based on historical experience and market intelligence; however, Gulf explicitly took into account the significant increase in requirements which will result from the start-up of the Petrosar plant in 1977. None of the submittors took into account the two world-scale naphtha-based petrochemical plants which the Alberta Board anticipates will be built between 1985 and 1995.

ii) Views of the Board

The Board's forecast of petrochemical feedstock demand in Canada is significantly higher than those provided by submittors, with estimated requirements of 242 Mb/d in 1994. The major assumptions underlying the Board's forecast are:

a. completion of the expansion of Gulf's Varennes plant in Quebec in 1976;

b. naphtha feedstock requirements for the Petrosar plant in Ontario of 31 Mb/d in 1977 and 35.5 Mb/d by 1979;

c. heavy fuel oil feedstock requirements of 30 Mb/d commencing in 1980, for a proposed electrode plant in Ontario;

d. the coming on stream of a second world-scale ethylene plant in Ontario by 1990, requiring 35.5 Mb/d of petrochemical feedstock;

e. the coming on stream in 1980 of an aromatics plant in Alberta, based on pentanes plus and requiring 25 Mb/d of feedstock;

f. the coming on stream in 1985 of a world-scale oil-based ethylene plant in Alberta, requiring 35.5 Mb/d of petrochemical feedstock.

The Board does not foresee significant reduction in the demand for petrochemical feedstocks over the forecast period due to conservation.

A comparison of petrochemical feedstock demand forecasts in Canada between 1974 and 1994 is shown in Figure 15.

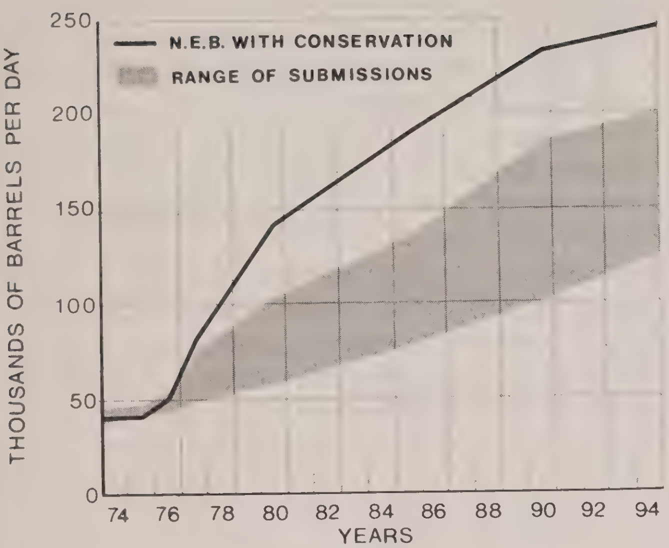


Figure 15: Comparison of Petrochemical Feedstock Demand, Canada, 1974-1994.

Other Products

For purposes of this report, the "other products" category consists of refinery-produced propane and propane mixes, butane and butane mixes; naphtha specialties, aviation gasoline, aviation turbo fuel, asphalt, coke, lubricating oils and greases and waxes.

i) Views of Submittors

The forecasts provided by submittors indicated general agreement that there would be relatively rapid growth in the demand for other products in Canada. The average annual growth rates implicit in the various forecasts ranged from a high of 5.9 percent (Gulf) to a low of 4.2 percent (Shell's conservation case), with some variation in the different regions. Shell estimated that the effect of conservation on the demand for other products would be 8.5 percent by 1994.

One component of the other products group, asphalt, received more attention than the others because of its importance to the operations of Murphy Oil Company Ltd. ("Murphy"), Husky and PanCanadian. For Canada as a whole, Murphy estimated that asphalt demand would be between 68 and 84 Mb/d in 1985. Murphy did not extend its forecast beyond 1985. Husky estimated that Canadian sales of asphalt would be 81 Mb/d in 1985, and 105 Mb/d in 1994. PanCanadian did not provide a specific forecast of asphalt demand.

ii) Views of the Board

The Board estimates that if there were no conservation in the use of other products over the forecast period, demand would be 440 Mb/d in 1994, implying an average annual growth rate of approximately 4.5 percent. There is some variation among the various regions, reflecting historical trends.

It is felt that there is little scope for conservation in the use of other products. Aviation turbo fuel demand might be reduced by increased jet engine efficiency and higher load factors, but such savings would probably not amount to more than 5 to 10 percent of aviation fuel requirements by 1994. Propane and butane demand might be affected by voluntary and government conservation measures in the residential sector, but propane and butane comprise only a small portion of the other products category and most of the markets for these products are supplied from natural gas processing plants. It is felt that there is a low probability

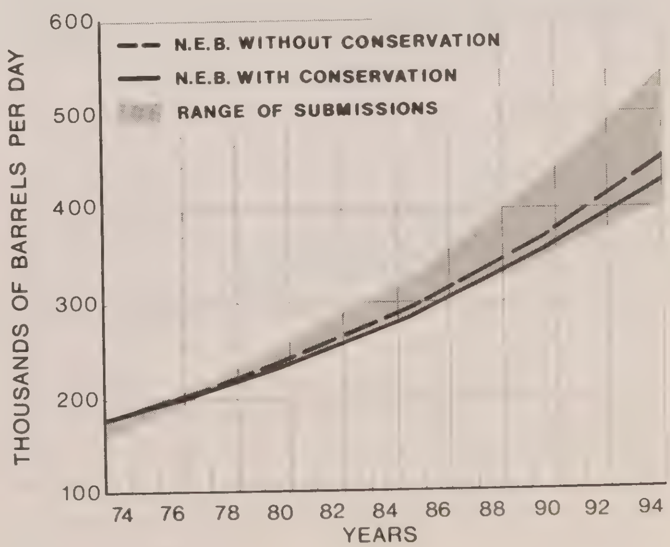


Figure 16: Comparison of Other Products Demand, Canada, 1974-1994.

of significant conservation in the use of the other individual products in this category. Altogether it is estimated that the demand for other products in Canada will be 5 percent less by 1994 than it would have been without conservation.

For the forecast period 1974 to 1994, a comparison of demand forecasts for other products is presented in Figure 16.

Requirement for Crude Oil and Equivalent

Future requirements for Canadian feedstocks derive not only from forecast demands for petroleum products within Canada, but also from the likely intentions of refiners and marketers regarding regional transfers and product imports and exports. Quantifying these intentions entails assumptions concerning refinery utilization, construction of new facilities, closure of existing plants and the future opportunities to sell Canadian products in foreign markets. It is not surprising, therefore, that forecasts of crude requirements provided to the Board as shown in Appendix E, Table 15 should exhibit considerable variation. The variation becomes more pronounced in the latter years of the forecast period. For the purposes of this report "Transfers" refers to those products which, because of shortages or price considerations, are transferred across the boundary known as the "Ottawa Valley Line". "Own use and loss" is determined by the level of refinery runs and the products manufactured. Inventory changes and butanes used for blending are the items included in "Other Adjustments".

i) Views of Submittors

For the area East of the Ottawa Valley Line ("EOV") it was generally submitted that product imports would show little increase over the period, although opinions differed over whether such imports would cease or continue at slightly below current levels. Most submittors assumed that product exports were necessary to ensure efficient operation of refineries. Texaco's assumption of increased refinery capacity in the Atlantic region between 1975 and 1980 resulted in significant increases in exports compared with other forecasts submitted. Net product transfers between the areas east and west of the Ottawa Valley Line were estimated to continue throughout the forecast period by all submittors except Shell which assumed a net balance in product supply and demand by 1985. Texaco's estimate of growth in crude requirements for the period 1974-1994 of 4.1 percent was the highest submitted. That forecast assumes no conservation. The lowest rate of growth, averaging 1.2 percent, was submitted by Imperial in its Case B forecast.

In the area West of the Ottawa Valley Line ("WOV") some forecasts showed continued imports primarily because of local shortfalls of product rather than any over-all deficiency in crude refining capacity. Other submittors, by projecting a sharp decline in imports, assumed these shortfalls would be met by additional capacity or interprovincial transfers. Product exports were estimated to continue at a marginal level except for the forecasts of Shell and Texaco which assumed relatively large volumes of exports in some years in order to balance refinery operations. The highest estimate of the average annual rate of growth in crude requirements for the period 1974-1994 was 4.2 percent submitted by Texaco; the lowest, averaging 2.1 percent, was provided by Imperial in its Case B forecast.

ii) Views of the Board

For the area EOV the Board has assumed that there will be excess refinery capacity until the post-1985 period. This circumstance coupled with the uncertainty of the availability of foreign markets suggests that there could be large fluctuations in the relative levels of product imports, exports and transfers. The Board has assumed, particularly in the period 1975-1977, a lower level of product imports and exports than in 1974 as Canadian marketers take advantage of excess supply to purchase their product requirements locally in preference to importing. Net transfers to the area WOV primarily of heavy fuel oil, reflecting the existing movements from Quebec to Ontario, are assumed to continue. The Board's estimate of the average annual rate of growth for the requirement of crude oil and equivalent, EOV, for the period 1974-1994, ranges from 2.5 percent to 3.2 percent, depending on the impact of demand-reducing programs.

For the area WOV the Board has projected excess refinery capacity until the post-1985 period on the basis of announced intentions to contruct additional capacity in Ontario and British Columbia. The Board believes there will be a tendency to reduce imports and thus improve refinery utilization. It assumes that operation at capacity will not be possible

between 1975 and 1985 because of anticipated conditions in competitive export markets. The Board's estimate of the average annual rate of growth WOV, 1974-1994, for requirements of crude and equivalent is 3.6 percent based on the forecast of demand which includes the effects of conservation and 4.3 percent for the estimate which excludes these effects.

On the basis of the Board's forecast of the total requirement in Canada for crude oil and equivalent, including the effect of conservation on demand, the average annual rate of growth for the period 1974-1994 is estimated to be 3.1 percent. Excluding any reduction in consumption due to conservation programs and policies the average annual rate of growth would be 3.8 percent.

In arriving at the forecast requirement for indigenous crude and equivalent shown on Appendix E, Table 16, the Board has included along with the demand WOV, the volumes of crude shipped to refiners EOV.

Figures 17, 18 and 19 show the average annual rate of growth of requirements for crude oil and equivalent EOV, WOV and total Canada, respectively.

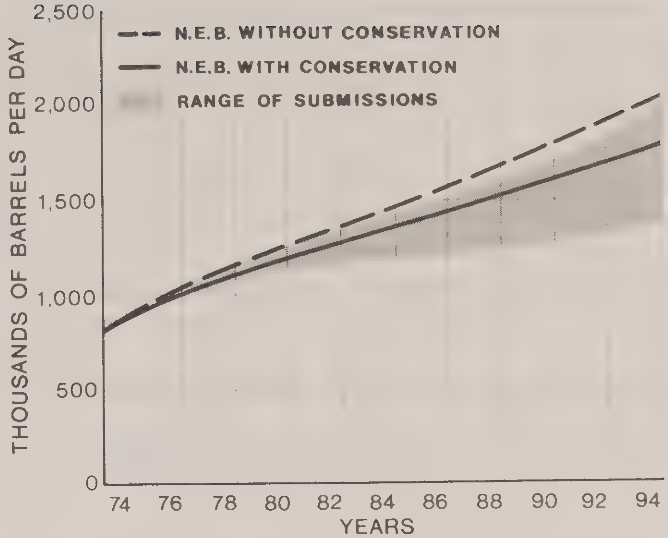


Figure 18: Requirements for Crude Oil and Equivalent West of Ottawa Valley Line.

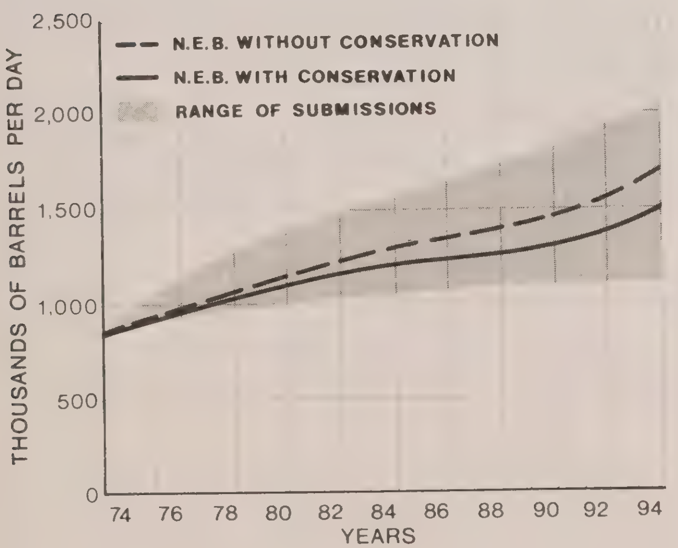


Figure 17: Requirements for Crude Oil and Equivalent East of Ottawa Valley Line.

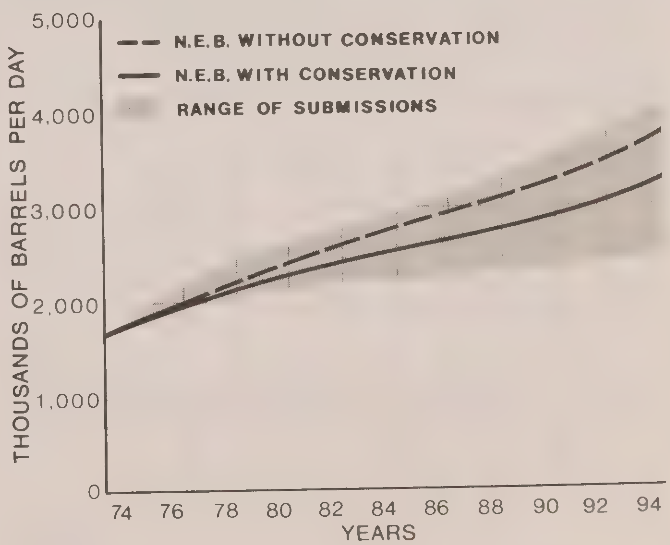


Figure 19: Requirements for Crude Oil and Equivalent Canada.

Protection for Canadian Requirements

The principles and procedures used by the Board to provide protection for Canadian requirements of indigenous crude oil and equivalent were outlined in its report of October, 1974. In brief, forecasts of annual average oil producibility and Canadian demand are made to determine the magnitude of annual surpluses which may materialize. If such forecasts show that surpluses will disappear in less than ten years, exports are phased out. The Board considers a ten-year period of protection to be appropriate, having regard to the accuracy of forecasting and, more particularly, to the lead time required to increase producibility through the development of new resources. Accordingly, if it is found necessary to phase out exports, annual maximum allowable export levels are determined by applying to each year's surplus a reduction factor representing the years remaining until surpluses disappear, divided by ten years.

To ensure that the Canadian consumers receive the benefits of oil conservation programs, estimates are made of the quantitative impact of such programs and the annual savings are subtracted from the apparent annual surplus before calculating allowable exports. In addition, the length of time until the supply-demand intersection is reached is determined using a demand projection which excludes the effects of conservation programs. In this way the benefits of conservation will be retained for Canadian consumers and will not flow through in the form of increased exports.

Mathematically, the procedure can be expressed as follows:

$$E = [P - (D+C)]\frac{t}{10} \qquad \text{(t not to exceed 10)}$$

Where E is the annual average volume in Mb/d available for export licensing during the year for which the determination is made.

Where P is the forecast annual average potential producibility of crude oil and equivalent in Mb/d during the year for which the determination is made.

Where D is the forecast annual average demand for Canadian use in Mb/d for western Canadian crude oil and equivalent during the year for which the determination is made.

Where C is the forecast total increase that would have occurred in demand for western Canadian crude oil and equivalent in Mb/d if conservation measures had not been effective.

Where t is the time during which supply is forecast to exceed Canadian demand, from January 1 of the year for which the determination is made, expressed to the nearest one tenth of a year, and extended to a maximum of ten years.

The Board's current forecasts of crude oil and equivalent producibility and Canadian demand for indigenous feedstocks are shown in Figure 20. The figure shows clearly that producibility is not adequate to meet demand for a period of ten years. In fact, the producibility curve intersects the demand curve in 5.0 years and accordingly exports should be reduced through application of the formula.

To determine the permissible level of exports in 1976 by means of the formula, it is necessary to anticipate the demand which will be served by the Sarnia to Montreal pipeline which is expected to be in operation during the last half of the year. The Board presently estimates that including line fill, the demand served by the pipeline, expressed as an average daily requirement for the year 1976, will be 100 Mb/d. Including this volume, the total requirement for indigenous feedstocks in 1976 is estimated to be 1041 Mb/d.

Assuming an average of 100 Mb/d for the Montreal pipeline, the 1976 allowable exports of crude and equivalent would be as follows:

$$E = [P - (D + C)]\frac{t}{10}$$

$$= [1981 - (1041 + 23)]\frac{5.0}{10}$$

$$= 459 \text{ Mb/d, (say 460 Mb/d)}$$

The Board favors, however, applying the formula in stages in 1976, with export levels related to the requirements of the Sarnia-Montreal pipeline. This would tend to allow Canadian production to be more uniform throughout the year, with resulting cash flow benefits to producers. It

would also result in a staged reduction in exports, giving U.S. customers some additional flexibility in making alternate supply arrangements.

With staging employed, the permissible exports, prior to commencement of operation of the Sarnia-Montreal pipeline would be:

$$E = [P - (D + C)]\,\frac{t}{10}$$

$$= [1981 - (941 + 23)]\,\frac{5.0}{10}$$

$$= 509 \text{ Mb/d, (say 510 Mb/d)}$$

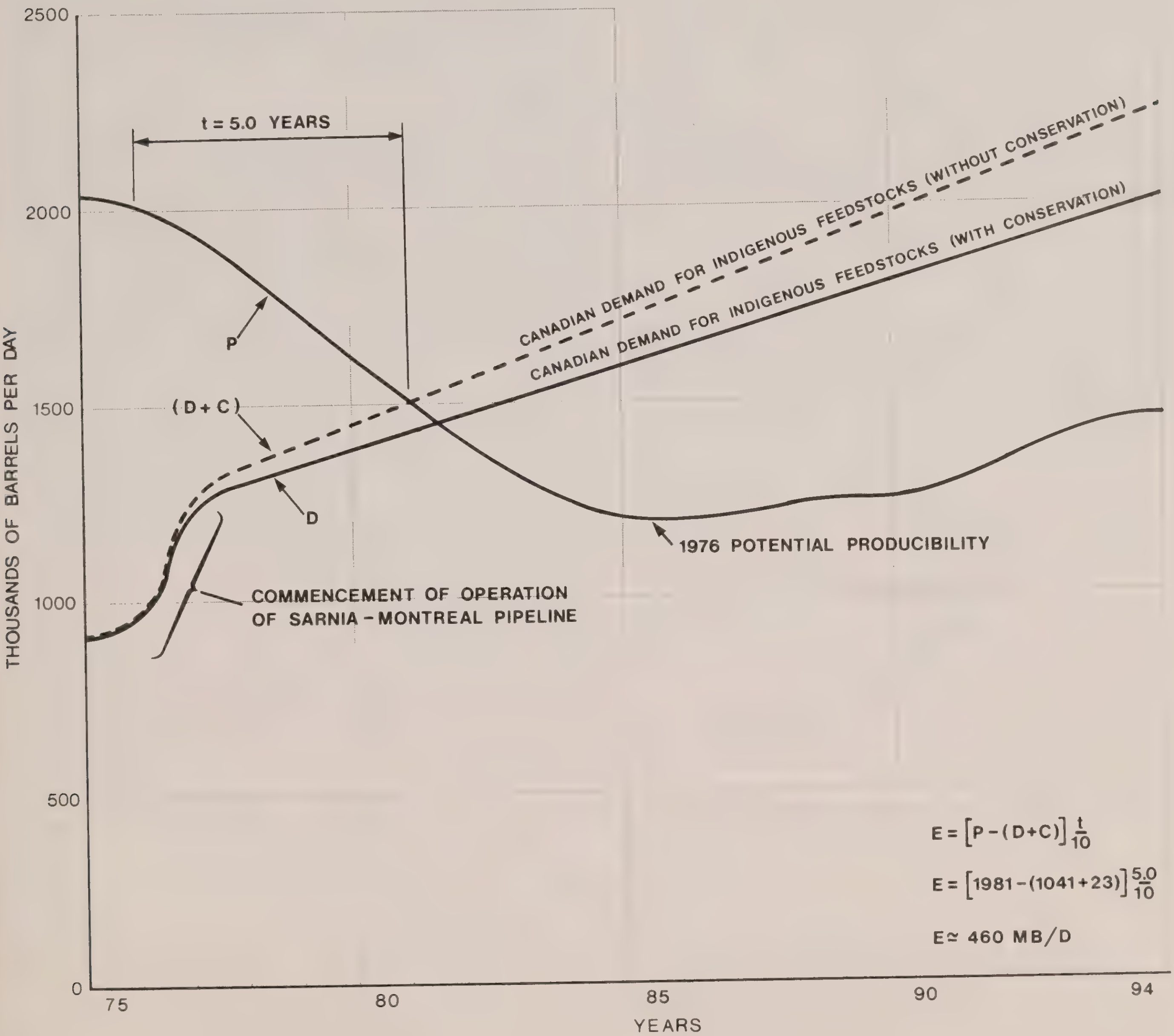


Figure 20: Calculation of Allowable Exports For 1976.

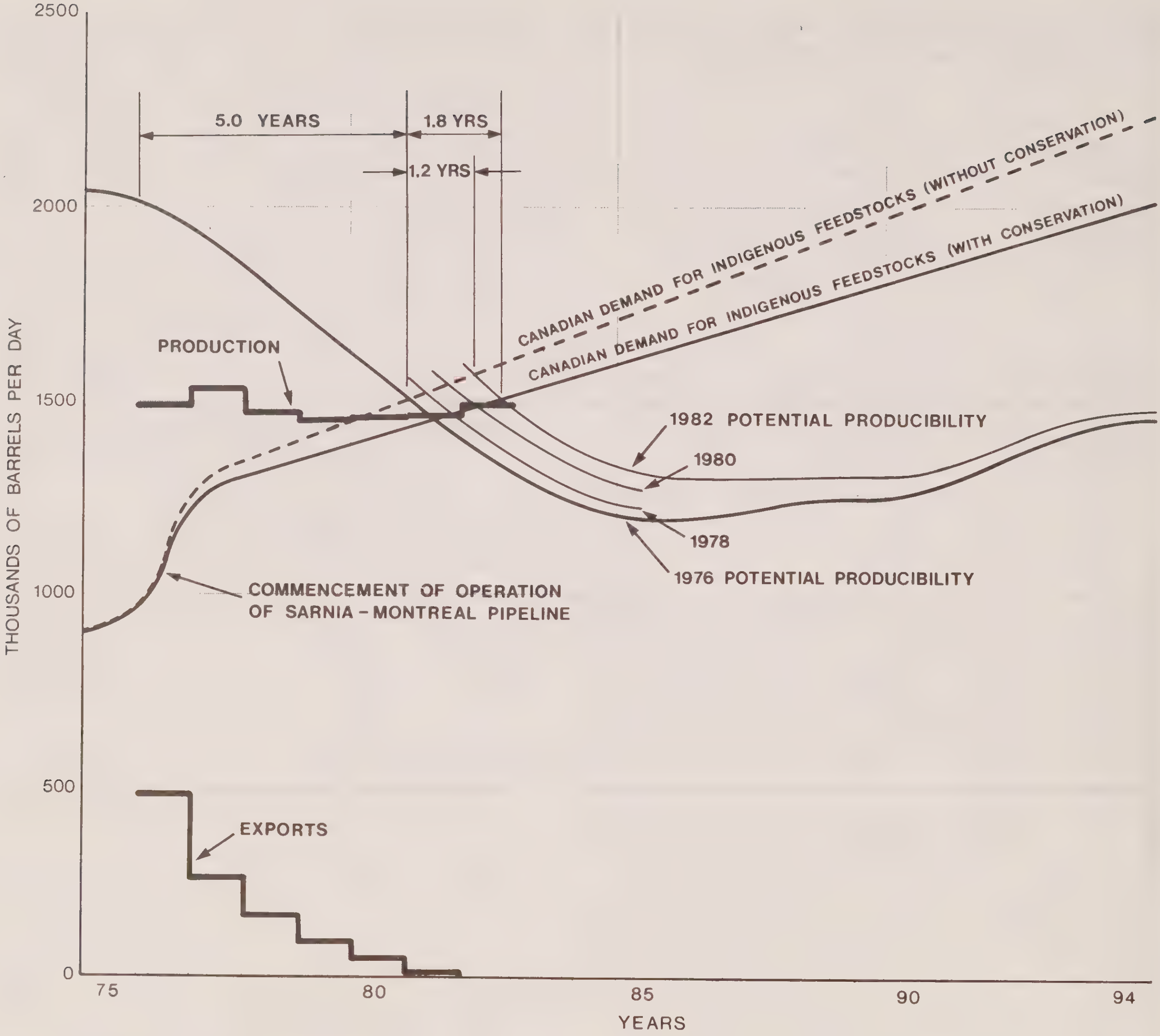


Figure 21: Long Term Effect of Protection Procedure.

The export levels after commencement of the operation of the Sarnia-Montreal pipeline would vary, depending upon the estimated requirements each month until the end of 1976 but in a month when the throughput is 250 Mb/d the export volume would be:

$$E = [P - (D + C)]\frac{t}{10}$$

$$= [1981 - (1191 + 23)]\ \frac{5.0}{10}$$

$$= 384 \text{ Mb/d, (say 385 Mb/d)}$$

The calculations shown above can be repeated for subsequent years to show the effect the protection procedure will have on exports in the future and how long the supply-demand intersection can be delayed. For each year considered, a supply and demand projection is constructed commencing in the year for which the calculation is being performed. To construct a potential producibility forecast for any year, the previous year's forecast of potential producibility has to be modified since a certain increment of producibility is available from the retained reserves resulting from the previous year's restricted rates of production.

The results of this long-term sensitivity test are shown in Figure 21. The lines shown above the 1976 potential producibility estimate incorporate the carry-forward of excess producibility employing a rate-cumulative technique. It is clear from Figure 21 that there are two factors which tend to delay the supply-demand intersection. The first is the effect of the protection formula which holds back reserves and producibility for future Canadian use. The second is the effect of conservation. The results of each of these actions are seen as the two points at which the 1982 potential producibility line intersects the two demand curves. The protection procedure results in a delaying of the supply-demand intersection by 1.2 years. Conservation results in an additional delay of 0.6 years. The combined effect is to delay the time of a possible supply-demand intersection by 1.8 years.

Also shown on the graph are two lines labelled production and exports. On the basis of the Board's current estimates of long-term producibility and demand, crude oil exports would be eliminated by the end of 1981.

Related Matters

Financial

i) Views of Submittors

Submittors were generally less optimistic in their producibility forecasts this year than they were a year ago. In terms of producibility from established reserves this was stated to be due mainly to the failure of the larger producing pools to perform as well at the peak as had been predicted. The other major reason cited, and this applies to all categories of supply, was the financial situation of producing companies. This was stated to be affecting exploration and development in two ways:

a) insufficient economic incentive to undertake major capital investment projects in Canada,

b) a general lack of confidence in the Canadian investment climate.

To support these claims, several companies provided estimates of their retained cash per barrel before and after the April 1974 price increase agreed upon by the Federal and Provincial governments. Estimates of retained cash prior to April, 1974, ranged from $1.53 per barrel to $2.04 per barrel. Estimates for a year later, following the $2.70 per barrel price increase and various tax and royalty changes, ranged from $0.24 per barrel to $2.26 per barrel.

In the short term, submittors felt that increases in producibility through major field facility expansions, infill drilling programs, etc. would be discouraged. For the longer term, there would be an adverse effect on exploration efforts, and expensive tertiary recovery programs.

Imperial proposed what it felt was a suitable program to stimulate investment. Firstly, companies must be permitted to retain 35 percent of the revenue stream after operating costs. Secondly, oil prices must be permitted to rise to world levels.

Submittors suggested that for confidence to be restored, they required stability in policy and favourable attitudes by governments.

Several companies were asked for views regarding an acceptable rate of return for the petroleum industry. Estimates ranged from 9 to 20 percent discounted cash flow rate of return. Some companies declined to cite any fixed rate of return because of the uncertainties of inflation.

ii) Views of the Board

The Board did not request financial information in its Notice of Hearing, or in its Outline for Submissions. However, the economic climate obviously has a major effect on producibility forecasting, and the Board has received the information under "related matters".

In its own producibility forecasts, the Board has assumed an economic climate suitable for vigorous petroleum exploration and development activities. The matter of revenue-sharing between producers and governments, and the appropriate crude oil prices are questions involving both levels of government and the Board does not feel it is appropriate to pursue the matter within the context of this report. It is the Board's opinion that the need for an adequate share of revenue flows to remain in the hands of industry is a matter now more fully appreciated by all levels and departments of government.

Licensing Exports by Grade of Crude Oil

This subsection of the report deals with the views received and the Board's views concerning the need to license exports of crude oil by grade. Although the Board did not specifically request views on this matter, evidence was accepted as being appropriate under "related matters".

For the purposes of this subsection, indigenous feedstocks include synthetic crude oil and pentanes plus.

i) Views of Submittors

Most of the evidence received from those addressing this question favoured the adoption of special licensing by crude type, particularly heavy crudes, whereas in previous discussions with interested parties the Board had received a generally negative response to the suggestion of separate licensing.

It was stated that heavy crude oil requires relatively stable producing conditions for maximum efficiency and that abrupt changes in production levels could impair ultimate recovery. It was also suggested that achieving high levels of production is not possible on the basis of the current Canadian market

for these crudes. There was general agreement that once Interprovincial Pipe Line Limited facilities were extended to Montreal, the domestic market could expand to include those Montreal refiners now utilizing imported heavy crudes. This would tend to maintain economic production levels without the need to rely on exports of these crudes. Until that time, however, heavy oil production would be greatly dependent upon export markets. Consequently, it was recommended that separate licensing be introduced to preserve the access of heavy crudes to export markets. Separate licensing was also advocated on the grounds that it would contribute to orderly marketing negotiations. There was some agreement, however, that appropriate pricing of heavy crudes could eliminate the need for such action. The evidence indicated that separate licensing was not required at this time to protect the needs of Canadian refiners.

The AERCB spoke against separate licensing and in favour of the free operation of purchaser nominations as the best method of ensuring maximum production of particular grades. It was stated that separate licensing increases administrative problems arising from unexpected changes in demand for and supply of particular grades and it was recommended that the Board adopt a common licensing system for all grades of crude oil and equivalent.

ii) Views of the Board

The Board has given consideration to separate licensing by grade of crude with respect to safeguarding the supply of specific types of feedstocks for Canadian market requirements and with respect to assuring an export market for heavy crude surplus to Canadian requirements.

Separate licensing by crude type as a method of assuring that the requirements of Canadian refiners are met is warranted whenever there exists sufficient risk of a particular type of crude being exported in preference to satisfaction of the Canadian demand for it. From information currently available, the Board does not see the need, at this time, to license heavy crude separately as a protection procedure for Canadian refineries. Furthermore, although pentanes plus have been licensed separately from other feedstocks since oil export controls were introduced in March, 1973, the Board intends to give consideration to the view expressed by the AERCB that separate licensing should be discontinued. The advantages and disadvantages will be discussed with the parties most affected, primarily from the viewpoint of providing protection for Canadian requirements.

From time to time, pentanes plus and heavy crude, each of which has certain production inflexibilities, have been in surplus supply, creating serious disposal problems. These circumstances provided opportunity for some assessment of the effectiveness of licensing by individual grade as a means of improving the flow of a particular stream to the export market. Experience has shown that the elimination of such surpluses usually turned upon pricing action.

Refiners WOV mainly process light and medium crude oils and, as stated previously in this report, most heavy crude oils are exported. With the projection of a phase-out of crude oil exports, it is understandable that some heavy oil producers anticipate increasing problems in the disposal of their production. The Board recognizes that separate licensing could have some beneficial effects on the marketing of heavy crude oils on the assumption that if export customers are severely limited in their choice of alternative sources of supply, they might be encouraged to purchase greater volumes of Canadian heavy crudes. There are, however, several potential developments which could improve the market demand for heavy crude oils. Some of these potential developments are:

(a) Preferential Import Allocations

Several of the refineries located in the so-called "Northern Tier" of the United States ("U.S.") have historically been the main export customers for heavy crudes. These are, physically, the most dependent of all U.S. refineries on supplies of Canadian crude oil. It is the Board's understanding that the U.S. Federal Energy Administration is reviewing methods whereby these refineries might receive preference in the allocation of Canadian imports. The extension of such preference may present greater opportunity for export sales of heavy crude oil.

(b) Exchange Agreements

Officials of the Canadian and U.S. Governments have had discussions on possible methods of continuing supplies of crude oil to refiners in the Northern Tier in view of the anticipated phasing out of Canadian exports. The method which appears to have greatest promise is the exchange of

crude oils between U.S. and Canadian companies. An example of such an exchange is one in which Canadian crude oil would be delivered to a Northern Tier refinery by a Canadian oil company and the U.S. company would deliver in return U.S. domestic crude oil or equivalent at Chicago for delivery to Ontario by the Lakehead — Interprovincial pipeline system. Such agreements, which it is expected would be on a barrel for barrel exchange basis, could maintain the demand for Canadian heavy crude oil if the United States refinery receiving the Canadian oil were a heavy crude processor.

(c) Increased Canadian Demand

Refineries located in Montreal are capable of processing heavy crude oils. It was stated in evidence that the opportunities to market Canadian heavy crudes would be increased when there is a pipeline connection from Western Canada to the Montreal area.

(d) Wellhead Price Adjustments

The demand for specific crude oils can usually be increased by price reductions. Since November 1974, export flows of heavy oils have been maintained by applying lower export charges than those for light and medium crude oils. It is some time since wellhead prices have been adjusted for quality differentials and action in this regard could increase the marketability of heavy crudes in both Canada and the U.S.

After giving due consideration to all relevant views and information it is the opinion of the Board that:

- demand for any crude type is primarily a function of its price and product yield for individual refiners relative to other feedstocks;
- licensing by grade introduces a degree of inflexibility which may aggravate any surplus problem associated with that grade; and
- licensing by grade for the purpose of expanding the market for particular types of crude would be largely ineffectual.

Licensing Exports by Province of Origin

This subsection of the report deals with the views received and the Board's views concerning the desirability of licensing exports of crude by province of origin. For practical purposes such a procedure would involve only oil from Alberta and Saskatchewan. Evidence on this subject was accepted under "related matters".

i) Views of Submittors

The two major oil producing provinces provided opposing views on this point.

Saskatchewan based its argument in favour of allocating the surplus between provinces on the relative differences in the economics of crude oil production in Alberta and Saskatchewan. It was pointed out that Alberta with its greater number of producing wells and its higher production rate per well has a greater capability for reducing output before reaching the minimum economic level of well production. Saskatchewan suggested that the Board, by not allocating the exportable surplus between provinces, places a disproportionate burden on Saskatchewan.

The imposition of a formal system of sharing the export market between Alberta and Saskatchewan was opposed by the AERCB on the grounds that it would mean not only a loss of provincial control over its energy resources, but would also result in administrative complications and increasing marketing rigidities. Concern was expressed that licensing the exportable surplus by producing province would inevitably lead to further extension of control over the domestic market and to allocation by crude type. It was suggested that experience to date has demonstrated the efficacy of a simple, flexible system of export controls.

ii) Views of the Board

Federal restriction on the export of crude oil inevitably has an effect on provincial control over energy resources. Increasing restriction may further affect provincial controls and might at some point give rise to inequities between individual provinces or producers of differing qualities of oil. Redress, however difficult and administratively complex, may then become desirable.

In the Board's judgment, such a point has not been reached. Moreover the Board is not yet persuaded that the adoption of licensing by province of origin would necessarily provide ready solutions to the multiplicity of problems which future developments could bring. The Board intends to keep the matter under continuing review.

Conclusions

This is a report on the evidence and opinions presented at the second hearing called by the Board in the matter of Canadian oil supply and Canadian oil requirements and volumes of oil surplus to such requirements. The views of submittors and of the Board concerning each of the main subject matters have been recorded in the preceding chapters. The Board's conclusions follow.

Supply

The Board requested that data be provided in a specified format to ensure that supply information for some 160 pools and areas was submitted on a uniform basis. While not all data sheets were complete in all respects, the Board is satisfied that the information provided, together with the detailed studies of its own staff, has resulted in a reliable forecast of the producibility from established reserves. However, this does not obviate the necessity of updating the forecast in the future in the light of changing circumstances.

As described more fully on page 2, the Board has adopted as its measure of potential producibility, the maximum producibility which would be achieved in a field or pool after a period of 90 days for any necessary remedial work. As indicated in Figure 5 on page 25 of the report, the forecast of producibility based on the current data and studies for established crude oil reserves differs little from the forecast presented in last year's report. The slightly lower producibility in the first half of the period is offset by slightly higher estimated producibility in the second half of the 20-year forecast period.

In reviewing the evidence presented and its staff studies, the Board concluded that its forecast of additions to crude oil reserves presented in the October 1974 report remained valid. Its estimate of producibility from these reserves additions as shown in Figure 6, page 27, is somewhat lower than that shown in the last report because reserves which have been added in the interval are now included in established reserves.

Similarly, the Board decided to adhere to its October 1974 forecast of producibility of pentanes plus from established reserves and reserves additions after reviewing the evidence presented at this hearing. This forecast is shown in Figure 7, page 28. A major change in the supply-availability picture results from the evidence presented concerning oil sands producibility. Although the Board has confidence that additional oil sands plants will be built, it has become apparent since the last hearing that such plants will not be constructed at the rate previously anticipated. For the reasons outlined on page 28 the Board has "stretched out" its previous schedule of plant construction, resulting in a million barrels per day productivity level being reached in 1994 instead of in 1991 as previously estimated. The difficulties in financing the Syncrude project have been well documented and need no further comment by the Board. In view of the long lead times required for planning and completion of oil sands plants, there is a need for co-operation between industry and governments to foster development of additional mining and in situ plants with the least possible delay.

In so far as frontier oil reserves are concerned, there has been insufficient change in the situation in the last year to warrant the Board giving any recognition to possible oil producibility from frontier regions within the 10-year protection period.

The Board's current estimate of potential producibility of crude oil and equivalent for the next 20 years is shown in Figure 9, page 31. Reductions in producibility in a particular year from the corresponding estimate in the October, 1974 report range from some 50 Mb/d or 2 percent in 1975 to some 180 Mb/d or 13 percent in 1984, and average some 130 Mb/d or 8 percent over the period to the end of 1993. These reductions are largely due to lower anticipated producibility from established reserves and reserves additions in the earlier years of the forecast and due to the changed outlook for the rate of oil sands development in the later years of the forecast.

Requirements and Conservation Considerations

The Board received more detailed evidence on Canada's requirements for petroleum products and for refinery feedstocks than was available to it for its last report. In addition, at this hearing definition and quantification of conservation as an element in demand forecasting were presented for the first time. The chapter entitled "Requirements and Conservation Considerations" deals with these matters in detail.

The Board appreciates the assistance given to it by submittors in the matter of estimating energy savings which reasonably can be attributed to "conservation". As shown in Figure 10, page 32, the Board presently estimates that conservation will result in a reduction in potential demand for petroleum products in Canada in 1994 of some 445 Mb/d or 13 percent. This is an aspect of demand forecasting which requires additional research and on which additional views will be sought by the Board as more experience is gained. The Board's estimates of requirements for indigenous feedstocks, before and after taking into account anticipated energy conservation, are shown in Appendix E, Table 16. As indicated in the discussion commencing on page 42, the plans of industry with respect to product imports, inter-regional transfers, product exports and therefore expected levels of refinery utilization must all be considered in forecasting feedstock requirements. The Board carefully considered the evidence and also utilized its own knowledge of the plans of individual companies concerning these operating matters.

In the October 1974 report, the Board recognized that security of products supply afforded by incremental refining capacity beyond normal Canadian requirements would be desirable. The report further expressed some concern that exports of refined products resulting from the processing of Canadian crude might increase significantly, but expressed confidence that the existing product licensing requirements provided sufficient checks and balances to ensure that refineries would not be built to process Canadian oil for the sole purpose of serving the export markets. The Board still believes this to be the case but also recognizes that as the level of authorized exports of petroleum products becomes a larger proportion of total exports of crude and products, it may become desirable to take it into account in the calculation of exportable surplus. Views of interested parties will be sought on this matter at the next hearing.

The Board's current estimate of requirements for indigenous feedstocks, including those EOV, before making provision for conservation are in reasonable agreement with those shown in the October 1974 report. For the years 1980, 1985 and 1990 for example, the current estimates are higher by some three to four percent. After allowing for conservation effects, the current estimates are lower than the previous estimates for the years 1980, 1985 and 1990 by 1.9, 4.2 and 6.3 percent, respectively.

Protection for Canadian Requirements

The application of the formula for the protection for Canadian requirements, using the supply and demand data resulting from the hearing has been discussed in the chapter entitled "Protection for Canadian Requirements" commencing on page 44.

As may be seen from Figure 21, page 46, the period of protection for Canadian requirements without conservation, for indigenous crude oil and equivalent would be 6.2 years from 1 January 1976. The time of intersection of the supply and demand curves, i.e. early 1982, compares to the corresponding intersection at the end of 1983 shown in the October 1974 report. The period of protection for the anticipated actual requirements with conservation is estimated to be 6.8 years.

The shortening of the period of protection by even as little as one year (over and above the passage of one year's time) must be regarded as serious when the total period of protection is now indicated to be only some seven years. In view of the extended lead-times required for pipelines and related facilities, there is a requirement for a commitment by both industry and government to a continuing review of the alternatives available to Canada to meet its long-term crude oil needs. Steps should be taken now to achieve this objective.

The strong views of the industry with respect to the need for a greater percentage of cash flow to be retained by industry to finance exploration and development have been recorded elsewhere in this report and in other recent reports of the Board. Steps taken by the Federal government and Provincial governments to reduce the taxation and royalty burdens, since the hearing, undoubtedly will help to restore impetus to the petroleum industry. Whether or not these steps are adequate can only be determined by continued surveillance of the effects on exploration and development activities.

On the demand side, it is the expressed policy of the Federal government to encourage conservation of energy by

all means possible and the provinces are also pursuing the same over-all objective. The matter of reducing demand for Canadian feedstocks through greater restriction of product exports will be a subject for future consideration.

Exports of Crude Oil and Equivalent

The application of the formula for the protection for Canadian needs results in allowable exports for 1976 of 460 Mb/d, as shown on page 44. However, the Board believes it would be in the interests of the producers and the U.S. export customers to have the formula applied on a monthly basis in 1976, to take into account demand served by the Sarnia-Montreal pipeline plus line fill. This should result in more uniform levels of production and higher levels of exports in the first half of 1976 and lower levels of exports in the second half of 1976 than would otherwise be the case. After 1976, average annual levels of exports could be authorized without causing wide fluctuations in producing rates. It is the Board's intention, therefore, to authorize exports in 1976 initially at the level of 510 Mb/d. After commencement of deliveries of oil to the Montreal pipeline extension at Sarnia, the export levels will be reduced in accordance with the formula. When the throughput of the line reaches the planned level of 250 Mb/d, the authorized level of exports will become 385 Mb/d.

The 1976 levels of exports mentioned above indicate significant reductions from the current level of authorized exports of 750 Mb/d. However, it may be recalled that in announcing the levels of exports for 1975, commencing at 800 Mb/d, the Honourable Donald Macdonald, Minister of Energy, Mines and Resources, indicated the intent to seek a reduced level of exports of 650 Mb/d commencing 1 July, 1975. However, as a result of reduced demands by export customers in the first half of 1975, authorized exports for the last half of the year were adjusted to 750 Mb/d.

The 1976 level of authorized exports forecast in the 1974 report was some 560 Mb/d, on the basis of the supply and demand data available at that time. The new levels of authorized 1976 exports, averaging 460 Mb/d, represent a reduction of some 100 Mb/d from the level anticipated for 1976 a year ago. As indicated in this report, the reduction is largely because of a changed outlook on forecast producibility from western Canadian sources of oil.

Licensing Systems

Finally, the desirability of licensing feedstock exports by grade of crude and/or by province of origin was again reviewed by the Board. In light of the mixed views expressed at the hearing and the Board's own knowledge and experience, the Board does not intend to reduce the flexibility in licensing by such segregation at this time. The system will be kept under continuous surveillance with a view to making such changes as may be warranted by future circumstances.

J. G. Stabback

Associate Vice-Chairman

Member

Member

Appendices

NOTICE OF HEARING

WHEREAS the Board has decided it is in the public interest to hold hearings periodically to receive evidence and advice from interested parties with respect to the potential producibility of Canadian oil, the domestic demand for oil, the effects of conservation on Canadian consumption, the surplus of Canadian oil and related matters.

TAKE NOTICE THAT the Board will be conducting such a public hearing in Calgary and Ottawa on days to be determined.

Interested parties are invited to file with the Board thirty (30) copies of written submissions in respect of the above matters before 22 March, 1975. A suggested outline for submissions can be obtained by writing to the Secretary of the Board at the Trebla Building, 473 Albert Street, Ottawa, Ontario, K1A 0E5 or by telephoning 613-992-5506.

DATED at the City of Ottawa, in the Province of Ontario, this 17th day of January, 1975.

NATIONAL ENERGY BOARD

"Robert A. Stead"
Robert A. Stead,
Secretary.

OUTLINE FOR SUBMISSIONS

Submittors are encouraged to use the following outline in the preparation of material for submission to the 1975 hearing into the matter of the producibility of Canadian oil, the domestic demand for feedstocks, and the effects of conservation on Canadian consumption, and the surplus of Canadian oil. The supply and demand categories outlined are based on the principles and procedures suggested at the Board's 1974 hearing in the matter of the exportation of oil.

For further information on Supply, questions should be directed to J.E.W. Buchholz, Research Division Chief, Engineering Branch, National Energy Board. The telephone number is (613) 995-6328.

Requests for additional information relating to Demand should be directed to B. Wells, Oil Policy Branch, National Energy Board; (613) 996-2171.

I. SUPPLY

Forecasts with respect to supply should present estimates of the average annual ability to produce Canadian crude oil and equivalent, unrestricted by demand, by province or territory for the period 1975-1994 for each of the following categories:

i) conventional crude oil from
   a) established reserves at 1 January, 1975
   b) reserves additions to existing reservoirs
   c) new discoveries in existing producing regions;

ii) pentanes plus from
   a) established reserves at 1 January, 1975
   b) reserves additions to existing reservoirs
   c) new discoveries in existing producing regions;

iii) oil recoverable from oil sands by
   a) surface mining
   b) in situ techniques; and

iv) frontier crude oil and equivalent.

Submissions should outline the technique used to forecast each supply category and all major assumptions should be stated. Grouping of categories is discouraged since it makes comparison of forecasts difficult.

In the case of (i) (a) above, the Board suggests a pool by pool forecasting technique be used by those submittors who have access to the requisite data base. In its deliberations following the 1974 oil exportation hearings, the Board adopted the views of those submittors who stated that producibility forecasts from established reserves could best be done on a pool by pool basis. In preparing its report on the hearings, the Board analysed representative pools in each province. Pools not analyzed in detail were aggregated by province and assumed to produce with reserves to production ratios equal to those of the analyzed pools.

During the 1975 hearing, the Board hopes to receive in evidence sufficient information to generate forecasts by grade of oil. In the Board's opinion, this can best be accomplished by grouping pools and reserves by feeder pipeline system. Where appropriate, streams moved through individual feeder pipeline systems will be divided by segregations made for quality reasons in current batching practices.

In order to achieve representation in each of the selected groupings, it is considered necessary to expand the number of pools to be analyzed in detail from 61 to approximately 160. A list of the selected pools is attached as Appendix 1. The following criteria were used by the Board in selecting these pools:

i) the pools should proportionately represent the major producing horizons in the study area;

ii) the pools in a study area should reflect the aggregate reserves to production ratio for the area;

iii) the number of pools should be kept to a minimum consistent with reasonable forecasting accuracy; and

iv) large pools are preferable to small pools for detailed analysis because better data are more generally available.

The Board expects that companies which are operators or major participants in any of the pools listed in Appendix 1 will submit a producibility forecast for these pools. While

this list is intended to serve as a guideline, submittors may wish to provide data on alternate or additional pools where they feel this would improve the accuracy of the forecast.

The Board requests that all pool producibility data be submitted in the format illustrated in Appendix 2. It is not the Board's intention to limit data to those requested in Appendix 2. Submittors are encouraged to submit any additional data, such as decline curve analyses, which they feel are pertinent to the matter of determining supply. The intention of this form is threefold:

i) a standard reporting procedure will result in submissions having a uniform format, thus making comparisons easier;

ii) inclusion of reservoir data and assumptions will help to resolve differences between producibility forecasts; and

iii) presentation of data in this detail will reduce the need for involved technical questioning of witnesses at the hearing.

The following guidance is offered to assist submittors in completing Appendix 2.

Section A

Normally, study pools will be identified by completing the spaces marked "FIELD" and "POOL". The space "UNIT" will be left blank except for:

i) cases listed in Appendix 1 where a unit, voluntary unit, or non-unit grouping of wells is to be studied; and

ii) cases in which the submittor may wish to provide a single producibility forecast for a pool, but may wish to provide reservoir data (e.g. recovery factors) on a unit basis. In these cases the submittor would use as many forms as required for the reservoir data, with only the first form in the series containing a pool producibility forecast.

Section B

In cases where the submittor has adopted "proven" and "probable" reserve definitions, the producibility forecast should be in respect of proven reserves. Future producibility should include production expected in respect of development programs which are contemplated with a high degree of certainty. Producibility is defined as the estimated average annual ability to produce, unrestricted by demand but restricted by reservoir performance, well density and well capacity, oil sands mining capacity and field processing capacity.

Section C

Reservoir data should also relate to established or proven reserves. The Board is requesting these data to provide a basis for resolving differences between producibility forecasts.

Section D

The intention of this section is to generate an overview of future reserves additions as to:

i) which formations or areas of Canada might make the largest contribution to reserves additions; and

ii) whether reserves additions will result mainly from improved recovery or new primary oil. These should be estimated using submittor's view of anticipated economic conditions. Since this may require elaboration, a space is provided for comments.

Information provided in Section D will assist the Board in translating forecasts of reserves additions into forecasts of producibility.

II. DEMAND

A primary objective of the hearing is to obtain forecasts of refinery feedstock needs to satisfy Canadian demand for refined petroleum products. These must be based largely on forecasts of total market sales of refined petroleum products adjusted for industry use and loss, exports and imports; regional forecasts must also be adjusted for product transfers. The separate contribution of butanes of gas plant origin to oil product supply has also to be distinguished, together with the proportion of foreign origin oil in total refinery runs.

Submittors proposing to supply information on demand are asked to prepare the data in sufficient detail to permit comparative evaluation. All forecasts should be expressed in thousands of barrels per day and should be accompanied by actual data for one year or more. It would be helpful if all

major assumptions were clearly described, especially those on relative prices of oil and other energy forms in various markets. Submittors should provide a quantitative reconciliation of the respective forecasts of product sales and feedstock requirements in the format illustrated in Appendix 3.

Product Sales — the suggested level of detail for estimates of total market product sales is as follows:

Forecast Period — Demand for years 1975, 1976, 1977, 1980, 1985, 1990, 1994.

Geographic Areas

Altantic

Quebec

Ontario

Manitoba

Saskatchewan

Alberta

British Columbia

Yukon and Northwest Territories

Total Canada

That part of Ontario east of the Ottawa Valley line, which estimates should also be included in the total Ontario forecast.

Product Categories

Motor Gasolines

Light Fuel Oil, Kerosene, Stove Oil

Diesel Fuel Oil

Heavy Fuel Oil

As described in Statistics Canada Publication 45-208

Petrochemical Feedstock — those products intended for petrochemical processing that are manufactured in oil refining operations (including gases and petrochemical naphtha).

Other products

Total Products

Feedstock requirements — the suggested level of detail for demand estimates of crude oil and equivalent is as follows:

Forecast Period — Demand for years 1975, 1976, 1977, 1980, 1985, 1990, 1994.

Geographic Areas — East of the Ottawa Valley Line
West of the Ottawa Valley Line

Total Canada

Feedstock Origins — Canadian

Foreign

Conservation

Submittors are requested to provide opinions and, if possible, estimates to assist the Board in identifying and quantifying reductions in Canadian oil demand resulting from conservation measures. 'Conservation measures' embrace

- those programs designed specifically to reduce petroleum demand,
- those policies whether general or specific relating to all energy forms, including those affecting price, which may have an impact on petroleum demand and
- shifts in consumer attitudes which are conservation oriented, but are not perceived to be in direct response to formal programs and policies.

NATIONAL ENERGY BOARD
DATED 29 January, 1975.

NATIONAL ENERGY BOARD

LIST OF POOLS AND POOL GROUPINGS

FOR CRUDE OIL PRODUCIBILITY FORECAST

NORTHWEST TERRITORIES

FIELD	POOL	UNIT
I. NORMAN WELLS		
Norman Wells	All	–

BRITISH COLUMBIA

FIELD	POOL	UNIT
I. BLUEBERRY-TAYLOR PIPELINES		
Aitken Creek	Gething	–
Blueberry	Debolt	–
Inga	Inga	–
Other	–	
II. TRANS-PRAIRIE PIPELINES LTD., – BEATTON RIVER: TAYLOR		
Beatton River	Halfway	–
Beatton River West	Bluesky-Gething	–
Crush	Halfway	–
Currant	Halfway	–
Milligan Creek	Halfway	–
Peejay	Halfway	–
Weasel	Halfway	–
Wildmint	Halfway	–
Other		–
III. TRANS-PRAIRIE PIPELINES LTD., – BOUNDARY LAKE: TAYLOR		
Boundary Lake	Boundary Lake	–

ALBERTA

FIELD	POOL	UNIT
I. BOW RIVER PIPE LINES LTD., LIGHT AND MEDIUM		
Choice	Blairmore	–
Kirkpatrick	Viking A	–
Provost	Viking CAK	–
Youngstown	ARCS	–
Other	–	–
II. BOW RIVER PIPE LINES LTD., HEAVY		
Bantry	Mannville A	–
Countess	Upper Mannville D	–
Grand Forks	Lower Mannville D	–
Lathom	Upper Mannville A	–
Taber South	Mannville B	–
Other	–	–
III. BPOG OPERATIONS LTD.		
Chauvin	Mannville A	–
Chauvin South	Sparky A+B	–
Chauvin South	Sparky H	–
Chauvin South	Lloydminster D	–
Other	–	
IV. CANADIAN INDUSTRIAL GAS AND OIL LTD.		
Joarcam	Viking	–
V. CREMONA PIPELINE		
Crossfield	Cardium A	–
Harmattan East	Rundle	–
Harmattan Elkton	Rundle C	–
Other	–	–

January 29, 1975

ALBERTA (Continued)

FIELD	POOL	UNIT
VI. FEDERATED PIPE LINES LTD.		
Carson Creek North	Beaverhill Lake A	–
Carson Creek North	Beaverhill Lake B	–
Judy Creek	Beaverhill Lake A	–
Judy Creek	Beaverhill Lake B	–
Swan Hills	Beaverhill Lake A+B	–
Swan Hills	Beaverhill Lake C	–
Swan Hills South	Beaverhill Lake A+B	–
Virginia Hills	Beaverhill Lake	–
Other	–	–
VII. GIBSON PETROLEUM COMPANY LIMITED		
Bellshill Lake	Blairmore	–
Thompson Lake	Blairmore	–
VIII. GULF ALBERTA PIPE LINE		
Clive	D-2A	–
Clive	D-3A	–
Drumheller	D-2B	–
Duhamel	D-2A	–
Duhamel	D-3B	–
Erskine	D-3	–
Fenn Big Valley	D-2A	–
Hussar	Glauconitic A	–
Joffre	D-2	–
Stettler	D-2A	–
Stettler	D-3A	–
West Drumheller	D-2A	–
Other	–	–
IX. HUSKY PIPELINE LTD. – LLOYDMINSTER AREA		
Lloydminster	Spky C and Gen Pete A	–
Lloydminster	Spy and Gen Pete C	–
Wainwright	Wainwright	–
Other	–	–
X. THE IMPERIAL PIPE LINE COMPANY, LIMITED – ELLERSLIE		
Acheson	D-3A	–
Golden Spike	D-3A	–
Other	–	–

ALBERTA (Continued)

FIELD	POOL	UNIT
XI. THE IMPERIAL PIPE LINE COMPANY, LIMITED – EXCELSIOR		
Excelsior	D-2	–
Fairydell – Bon Accord	D-3A	–
Other	–	–
XII. THE IMPERIAL PIPE LINE COMPANY, LIMITED – LEDUC		
Leduc-Woodbend	D-2A	–
Leduc-Woodbend	D-3A	–
Other	–	–
XIII. THE IMPERIAL PIPE LINE COMPANY, LIMITED – REDWATER		
Redwater	D-3	–
XIV. MURPHY OIL COMPANY LTD.		
Cessford	Total	–
Coutts	Total	–
Red Coulee	Total	–
Other	–	–
XV. PEACE RIVER OIL PIPE LINE CO. LTD.		
Goose River	BHL A	–
Kaybob	BHL A	–
Kaybob South	Triassic A	–
Nipisi	Gilwood A	–
Simonette	D-3	–
Snipe Lake	BHL	–
Sturgeon	Lake	–
Sturgeon Lake South	D-3	–
Utikuma	KR Sand A	–
Other	–	–

ALBERTA (Continued)

FIELD	POOL	UNIT
XVI. PEMBINA PIPE LINE LTD.		
Pembina	Cardium	—
Willesden Green	Cardium A	—
Other	—	—
XVII. RAINBOW PIPE LINE COMPANY, LTD.		
Mitsue	Gilwood A	—
Nipisi	Gilwood A	—
Rainbow	KR A	—
Rainbow	KR B	—
Rainbow	KR F	—
Rainbow	KR AA	—
Rainbow South	KR A	—
Rainbow South	KR B	—
Rainbow South	KR E	—
Virgo	Total	—
Zama	Total	—
Other	—	—
XVIII. RANGELAND PIPE LINE COMPANY LIMITED		
Ferrier	Cardium E	—
Gilby	Jurassic B	—
Gilby	Viking A	—
Innisfail	D-3	—
Joffre	D-2	—
Medicine River	Glauconitic A	—
Medicine River	Jurassic A	—
Medicine River	Jurassic D	—
Sundre	Rundle A	—
Willesden Green	Cardium A	—
Other	—	—

ALBERTA (Continued)

FIELD	POOL	UNIT
XIX. TEXACO EXPLORATION CANADA LTD.		
Bonnie Glen	D-3A	—
Glen Park	D-3A	—
Westerose	D-3	—
Wizard Lake	D-3A	—
Other	—	—
XX. TWINING PIPELINE DIVISION		
Twining	Run. A+L.M.A.	—
Twining North	Rundle	—
XXI. VALLEY PIPE LINE		
Turner Valley	Rundle	—
XXII. TRUCK AND TANK CAR		
Total L and M	—	—
Total Heavy	—	—

SASKATCHEWAN

	FIELD	POOL	UNIT
I.	HUSKY PIPELINE LTD. + MURPHY OIL COMPANY LTD.		
	Aberfeldy	Sparky Sand	Aberfeldy
	South Aberfeldy	Sparky Sand	South Aberfeldy Sparky Vol.
	Dulwich	Sparky Sand	—
	Epping	Sparky Sand	Non-Unit
	Epping	Sparky Sand	S.W. Epping Sparky Vol. Unit No. 1
	Furness	Sparky Sand	—
	Golden Lake North	Waseca and Sparky	Golden Lake Vol. Unit
	Golden Lake North	Waseca Sand	Non-Unit
	Golden Lake South	Sparky Sand	—
	Golden Lake South	Waseca Sand	—
	Gully Lake	Waseca Sand	—
	Lashburn	Waseca Sand	Lashburn Waseca Vol. Unit
	Lone Rock	Sparky Sand	—
	Other	—	—
II.	BOW RIVER PIPE LINES LTD.		
	Coleville	Bakken Sand	—
	Dodsland	Viking Sand	Gleneath Unit
	Dodsland	Viking Sand	Eagle Lake Viking Vol. Unit
	North Hoosier	Bakken Sand	North Hoosier Bakken Sand Vol. Unit
	North Hoosier	Basal Blairmore Sand	North Hoosier Sand Blairmore Vol. Unit
	Smiley-Dewar	Viking	—
	Other	—	—
III.	SOUTH SASKATCHEWAN PIPE LINE COMPANY		
	Battrum	Roseray Sand	Battrum Unit No. 1
	Cantuar	Cantuar Sand	Cantuar Unit
	Dollard	Upper Shaunavon	Dollard Unit
	Fosterton	Roseray Sand	Fosterton Main Unit
	Gull Lake North	Upper Shaunavon	Gull Lake Unit
	Instow	Upper Shaunavon	Instow Unit
	Main Success	Roseray Sand	Success Main Unit
	North Premier	Roseray Sand	North Premier Unit No. 3
	South Success	Roseray Sand	Success Unit
	Rapdan	Upper Shaunavon	Rapdan Unit
	Other	—	—

SASKATCHEWAN (Continued)

FIELD	POOL	UNIT
IV. WESTPUR PIPE LINE COMPANY — MIDALE MEDIUM		
Benson	Midale	Unit
Flat Lake	Ratcliffe	Vol. Unit No. 1
Innes	Frobisher	—
Lost Horse Hill	Frobisher-Alida	Vol. Unit No. 1
Midale	Central Midale	Unit
Midale	Central Midale	Non-Unit
Sherwood	Frobisher	—
Viewfield	Frobisher	—
Weyburn	Midale	Unit
Weyburn	Midale	Non-Unit
Other	—	—
V. WESTPUR PIPE LINE COMPANY — S.E. SASKATCHEWAN LIGHT		
Alida East	Alida	Unit
Carnduff	Midale	East Unit
Ingoldsby	Frobisher-Alida	Vol. Unit
Kenosee	Tilston	Vol. Unit
Parkman	Tilston-Souris Valley	—
Queensdale East	Frobisher-Alida	Non-Unit
Rosebank	Frobisher-Alida	Vol. Unit No. 1
Steelman	Midale	Unit IA
Steelman	Midale	Unit II
Steelman	Midale	Unit IV
Steelman	Midale	Unit VI
Willmar	Frobisher-Alida	Non-Unit
Workman	Frobisher	Vol. Unit No. 1
Other	—	—

MANITOBA

FIELD	POOL	UNIT
I. TRANS-PRAIRIE PIPE LINES LTD.		
Daly	Miss.	—
Routledge	Miss.	—
N. Virden Scallion	Miss.	—
Virden-Roselea	Miss.	—
Other	—	-

ONTARIO

FIELD	POOL	UNIT
I. ONTARIO		
Ontario	All	—

A. NATIONAL ENERGY BOARD CRUDE OIL PRODUCIBILITY FORECAST

FIELD:

POOL UNIT

SUBMITTOR DATE

B. PRODUCIBILITY FORECAST

From
Established Reserves at 1-1-75

YEAR	BARRELS PER DAY
1975	....
1976	....
1977	....
1978	....
1979	....
1980	....
1981	....
1982	....
1983	....
1984	....
1985	....
1986	....
1987	....
1988	....
1989	....
1990	....
1991	....
1992	....
1993	....
1994	....

C. OIL RESERVOIR DATA

For
Established Reserves at 1-1-75

Area, acres	....
Average pay, ft	....
Rock volume, acre-ft	....
Porosity, %	....
Connate water, %	....
Shrinkage, %	....
Initial oil in place, Mstb	....
Hor, permeability, md	....
Vert. permeability, md	....
Pressure datum, ft. ss.	....
Initial pressure, psia	....
Initial oil viscosity, cp	....
Current pressure, psia	....
Current oil viscosity, cp	....
Primary recovery, %	....
Improved recovery, %	....
Improved recovery mechanism	....
Total recoverable oil, Mstb	....
Cumulative oil production to 1-1-75, Mstb	....

D. POTENTIAL RESERVES ADDITIONS

DRILLING POTENTIAL

No. of wells .... Recoverable Oil, Mstb ....

Comments ....

IMPROVED RECOVERY POTENTIAL

Method .... Recoverable Oil, Mstb ....

Comments ....

RECONCILIATION OF TOTAL MARKET PRODUCT SALES & FEEDSTOCK REQUIREMENTS*

Thousands of Barrels Per Day

	1973					
	East of the Ottawa Valley line		**West of the Ottawa Valley line**		**Canada**	
Total market product sales		756		836		1592
Product imports	(75)		(30)		(105)	
Product exports	97		17		114	
Net exports/(imports)		22		(13)		9
Net product transfers out/(in)		46		(46)		0
Industry use and loss		54		60		114
Total feedstock requirements		878		837		1715
Deduct gas plant butanes supplied to refineries		(1)		(13)		(14)
Deduct foreign feedstock refined		(859)		(18)		(877)
Canadian feedstock refined		18		806		824

*Quantities shown are only illustrative.

January 29, 1975

NATIONAL ENERGY BOARD ESTIMATE OF ESTABLISHED RESERVES OF CONVENTIONAL CRUDE OIL

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/75 MMstb	Remaining Reserves at 1/1/75 MMstb
NORTHWEST TERRITORIES			
1. Norman Wells			
Norman Wells	60.0	17.7	42.3
BRITISH COLUMBIA			
1. Blueberry — Taylor Pipelines			
Aitken Creek — Gething	5.3	3.9	1.4
Blueberry — Debolt	14.6	9.9	4.7
Inga — Inga	42.0	20.2	21.8
Other	4.4	1.9	2.5
2. Trans-Prairie Pipelines Ltd.: Beatton River — Taylor			
Beatton River — Halfway	8.2	5.8	2.4
Beatton River West — Bluesky Gething	4.4	2.0	2.4
Crush — Halfway	3.8	2.1	1.7
Currant — Halfway	2.2	1.7	0.5
Milligan Creek — Halfway	41.7	34.2	7.5
Peejay — Halfway	59.4	45.4	14.0
Weasel — Halfway	15.1	9.7	5.4
Wildmint — Halfway	7.4	6.6	0.8
Other	7.4	3.0	4.4
3. Trans-Prairie Pipelines Ltd.: Boundary Lake — Taylor			
Boundary Lake Unit No. 1	106.6	49.1	57.5
Boundary Lake Unit No. 2	67.8	39.4	28.4
Other	16.4	13.4	3.0
British Columbia Total	**406.7**	**248.3**	**158.4**
ALBERTA			
1. Bow River Pipe Lines Ltd.: Light & Medium			
Provost — Viking CAK	110.0	16.9	93.1
Other	1.3	1.0	0.3

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/75 MMstb	Remaining Reserves at 1/1/75 MMstb
ALBERTA (continued)			
2. Bow River Pipe Lines Ltd.: Heavy			
Bantry – Mannville A	40.6	19.5	21.1
Countess – Upper Mannville D	24.5	8.5	16.0
Countess – Upper Mannville H	14.0	3.7	10.3
Grand Forks – Lower Mannville D	38.9	2.9	36.0
Hays – Lower Mannville A	9.4	3.9	5.5
Lathom – Upper Mannville A	10.1	2.8	7.3
Taber – Mannville D	11.8	4.7	7.1
Taber South – Mannville B	12.4	7.7	4.7
Other	77.0	30.5	46.5
3. BPOG Operations Ltd.			
Chauvin – Mannville A	7.4	4.5	2.9
Chauvin South – Sparky A & B	7.0	3.0	4.0
Chauvin South – Sparky H	1.4	0.3	1.1
Chauvin South – Lloydminster D	1.7	0.7	1.0
Other	10.7	2.5	8.2
4. Canadian Industrial Gas and Oil Ltd.			
Joarcam – Viking	90.2	74.9	15.3
5. Cremona Pipeline			
Crossfield – Cardium A	17.5	14.7	2.8
Harmattan East – Rundle	80.8	37.6	43.2
Harmattan Elkton – Rundle C	53.9	33.2	20.7
Other	31.6	26.0	5.6
6. Federated Pipe Lines Ltd.			
Carson Creek North – BHL A	36.2	11.7	24.5
Carson Creek North – BHL B	124.1	41.8	82.3
Judy Creek – BHL A	390.0	153.3	236.7
Judy Creek – BHL B	125.0	50.2	74.8
Swan Hills – BHL A & B	778.0	280.5	497.5
Swan Hills – BHL C	190.0	62.8	127.2
Swan Hills South – BHL A & B	452.8	146.8	306.0
Virginia Hills – BHL	155.0	71.9	83.1
Other	37.6	8.3	29.3

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/75 MMstb	Remaining Reserves at 1/1/75 MMstb
ALBERTA (continued)			
7. Gibson Petroleum Company Limited			
Bellshill Lake – Blairmore	49.9	21.6	28.3
Thompson Lake – Blairmore	4.1	2.2	1.9
8. Gulf Alberta Pipe Line			
Clive – D-2A	21.6	5.2	16.4
Clive – D-3A	43.4	12.7	30.7
Drumheller – D-2B	10.3	3.1	7.2
Duhamel – D-2A	5.8	4.7	1.1
Duhamel – D-3B	7.1	5.1	2.0
Erskine – D-3	26.1	17.8	8.3
Fenn Big Valley – D-2A	239.0	141.0	98.0
Hussar – Glauconitic A	20.6	10.2	10.4
Joffre – D-2 (33%)	23.1	10.1	13.0
Stettler – D-2A	24.0	20.5	3.5
Stettler – D-3A	23.2	12.4	10.8
West Drumheller – D-2A	27.5	20.0	7.5
Other	134.3	81.6	52.7
9. Husky Pipeline Ltd.			
Lloydminster – Sparky C and GP A	7.2	4.3	2.9
Lloydminster – Sparky and GP C	18.0	10.0	8.0
Wainwright – Wainwright	52.4	28.7	23.7
Other	10.6	6.9	3.7
10. The Imperial Pipe Line Company, Limited: Ellerslie			
Acheson – D-3A	107.9	60.4	47.5
Golden Spike – D-3A	210.0	128.2	81.8
Other	57.2	30.2	27.0
11. The Imperial Pipe Line Company, Limited: Excelsior			
Excelsior – D-2	23.8	17.9	5.9
Fairydell Bon Accord – D-3A	11.5	7.3	4.2
Other	4.1	3.3	0.8
12. The Imperial Pipe Line Company, Limited: Leduc			
Leduc Woodbend – D-2A	86.5	84.8	1.7
Leduc Woodbend – D-3A	239.1	207.1	32.0
Other	40.2	36.5	3.7

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/75 MMstb	Remaining Reserves at 1/1/75 MMstb
ALBERTA (continued)			
13. The Imperial Pipe Line Company, Limited: Redwater			
Redwater – D-3	797.0	540.6	256.4
14. Murphy Milk River Pipe Line			
Coutts – Total	5.0	1.0	4.0
Red Coulee – Total	3.2	2.6	0.6
Manyberries – Total	5.6	1.2	4.4
Other	9.3	4.7	4.6
15. Peace River Oil Pipe Line Co. Ltd.			
Goose River – BHL A	49.2	14.9	34.3
Kaybob – BHL A	114.0	53.8	60.2
Kaybob South – Triassic A	87.5	26.3	61.2
Nipisi – Gilwood A (33%)	99.0	30.5	68.5
Simonette – D-3	57.8	19.7	38.1
Snipe Like – BHL	77.0	29.1	47.9
Sturgeon Lake – D-3	22.8	13.3	9.5
Sturgeon Lake South – D-3	157.0	65.9	91.1
Utikuma – KR Sand A	24.9	7.8	17.1
Other	127.4	38.6	88.8
16. Pembina Pipe Line Ltd.			
Pembina – Cardium	1367.3	768.8	598.5
Pembina – Keystone Belly River B	58.9	14.8	44.1
Willesden Green – Cardium A (70%)	107.8	37.6	70.2
Other	99.9	33.1	66.8
17. Rainbow Pipe Line Company, Ltd.			
Mitsue – Gilwood A	341.0	103.1	237.9
Nipisi – Gilwood A (67%)	201.0	61.8	139.2
Rainbow – KR A	79.2	25.2	54.0
Rainbow – KR B	161.0	52.5	108.5
Rainbow – KR F	110.0	34.5	75.5
Rainbow – KR AA	84.0	17.5	66.5
Rainbow South – KR A	19.4	5.9	13.5
Rainbow South KR B	32.8	7.0	25.8
Rainbow South KR E	25.2	6.4	18.8
Virgo – Total	70.7	22.4	48.3
Zama – Total	122.4	40.5	81.9
Other	291.2	76.6	214.6

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/75 MMstb	Remaining Reserves at 1/1/75 MMstb
ALBERTA (continued)			
18. Rangeland Pipe Line Company Limited			
Ferrier – Cardium E	31.7	4.5	27.2
Gilby – Jurassic B	23.2	7.9	15.3
Gilby – Viking A	16.2	13.6	2.6
Innisfail – D-3	74.4	40.1	34.3
Joffre – D-2 (67%)	47.0	20.4	26.6
Medicine River – Glauconitic A	11.2	3.3	7.9
Medicine River – Jurassic A	11.3	5.6	5.7
Medicine River – Jurassic D	18.8	4.3	14.5
Sundre – Rundle A	32.0	19.1	12.9
Willesden Green – Cardium A (30%)	46.2	16.1	33.1
Other	198.0	82.2	112.8
19. Texaco Exploration Canada Ltd.			
Bonnie Glen – D-3A	460.3	230.4	229.9
Glen Park – D-3A	21.1	10.7	10.4
Westerose – D-3	133.4	54.5	78.9
Wizard Lake – D-3A	323.0	146.5	176.5
Other	2.6	2.2	0.4
20. Trans-Prairie Pipelines Ltd.: Boundary Lake South			
Boundary Lake South – Triassic E	22.5	3.9	18.6
Other	4.1	0.6	3.5
21. Twining Pipeline Division			
Twining – Rundle A and LM A	22.4	3.5	18.9
Twining North – Rundle	3.2	1.4	1.8
22. Valley Pipe Line			
Turner Valley – Rundle	138.0	124.2	13.8
23. Truck and Tank Car			
Cessford – Total	21.2	13.6	7.6
Other Heavy	23.2	10.9	12.3
Light & Medium – Total	23.4	16.2	7.2
Alberta Total	**10986.3**	**5114.0**	**5872.3**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/75 MMstb	Remaining Reserves at 1/1/75 MMstb
SASKATCHEWAN			
1. Husky Pipeline Ltd. & Murphy Oil Company Ltd.			
Aberfeldy – Sparky, Aberfeldy Unit	29.2	18.6	10.6
South Aberfeldy – Sparky, Voluntary Unit	9.7	5.1	4.6
Dulwich – Sparky	11.1	8.2	2.9
Epping – Sparky, Non-Unit	12.1	7.6	4.5
South Epping Unit No. 1 – Sparky & GP	17.3	9.7	7.6
S.W. Epping Sparky Vol. Unit No. 1	5.4	2.3	3.1
Furness – Sparky	2.8	1.1	1.7
Golden Lake North – Waseca & Sparky, Vol. Unit	9.7	4.2	5.5
Golden Lake North – Waseca, Non-Unit	1.3	0.5	0.8
Golden Lake South – Sparky	2.0	0.8	1.2
Golden Lake South – Waseca	5.3	2.0	3.3
Gully Lake – Waseca, Vol. Unit No. 1	3.2	1.5	1.7
Gully Lake – Waseca, Non-Unit	1.6	0.7	0.9
Lashburn – Waseca, Vol. Unit	5.3	3.8	1.5
Lone Rock – Sparky	7.1	6.6	0.5
Other	33.1	19.7	13.4
2. Bow River Pipe Lines Ltd.			
Coleville – Bakken	38.2	26.6	11.6
Dodsland – Viking, Gleneath Unit	13.6	6.6	7.0
Dodsland – Viking, Eagle Lake Vol. Unit	15.8	7.1	8.7
North Hoosier – Bakken, Vol. Unit	6.5	2.3	4.2
North Hoosier – Basal Blairmore, Vol. Unit	3.6	1.9	1.7
Smiley Dewar – Viking	32.7	19.7	13.0
Other	34.3	19.5	14.8
3. South Saskatchewan Pipe Line Company			
Battrum – Roseray, Unit No. 1	36.1	21.4	14.7
Cantuar Main – Cantuar, Unit	23.7	16.7	7.0
Dollard – Upper Shaunavon, Unit	83.6	66.2	17.4
Fosterton – Roseray, Main Unit	64.2	47.0	17.2
Gull Lake North – Upper Shaunavon, Unit	19.6	15.7	3.9
Instow – Upper Shaunavon, Unit	51.0	36.2	14.8
Main Success – Roseray, Unit	16.4	14.6	1.8
North Premier – Roseray, Unit No. 3	13.2	10.6	2.6
Rapdan – Upper Shaunavon, Unit	17.5	10.2	7.3
South Success – Roseray, Unit	23.3	17.7	5.6
Suffield – Upper Shaunavon, Unit No. 2	6.2	2.3	3.9
Verlo – Roseray, Unit	12.9	3.3	9.6
Other	174.4	104.4	70.0

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/75 MMstb	Remaining Reserves at 1/1/75 MMstb
SASKATCHEWAN (continued)			
4. Westpur Pipe Line Company – Midale Medium			
Benson – Midale, Unit	10.5	5.9	4.6
Flat Lake – Ratcliffe, Vol. Unit No. 1	11.2	4.7	6.5
Innes – Frobisher	14.6	7.3	7.3
Lost Horse Hill – Frobisher Alida, Vol. Unit No. 1	13.4	8.3	5.1
Midale – Central Midale, Unit	109.3	71.4	37.9
Midale – Central Midale, Non-Unit	6.1	4.3	1.8
Sherwood – Frobisher	11.4	7.5	3.9
Viewfield – Frobisher	9.8	2.0	7.8
Weyburn – Midale, Unit	331.9	202.9	129.0
Weyburn – Midale, Non-Unit	6.0	3.3	2.7
Other	87.7	52.4	35.3
5. Westpur Pipe Line Company – S.E. Sask. Light			
Alida East – Alida, Unit	11.7	9.5	2.2
Carnduff – Midale, East Unit	16.4	14.0	2.4
Elmore – Frobisher	11.3	7.0	4.3
Ingoldsby – Frobisher Alida, Vol. Unit	16.8	10.6	6.2
Kenosee – Tilston, Vol. Unit	10.8	5.9	4.9
Parkman – Tilston Souris Valley	17.1	13.6	3.5
Queensdale East-Frobisher Alida, Non-Unit	27.7	17.0	10.7
Rosebank – Frobisher Alida, Vol. Unit No. 1	23.6	18.2	5.4
Steelman – Midale, Unit IA	60.6	40.5	20.1
Steelman – Midale, Unit II	53.6	39.9	13.7
Steelman – Midale, Unit IV	31.8	20.6	11.2
Steelman – Midale, Unit VI	58.2	46.4	11.8
Willmar – Frobisher Alida, Non-Unit	18.7	12.6	6.1
Workman – Frobisher, Vol. Unit No. 1	11.7	7.5	4.2
Other	294.8	201.9	92.9
Saskatchewan Total	**2119.7**	**1377.6**	**742.1**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/75 MMstb	Remaining Reserves at 1/1/75 MMstb
MANITOBA			
1. Trans-Prairie Pipelines Ltd.			
Daly — Mississippian	21.0	16.7	4.3
Routledge — Mississippian	14.8	11.6	3.2
North Virden Scallion — Mississippian	70.4	43.3	27.1
Virden Roselea — Mississippian	43.2	28.0	15.2
Other	11.4	6.4	5.0
Manitoba Total	**160.8**	**106.0**	**54.8**
ONTARIO			
1. Ontario			
Ontario — Total	**60.7**	**52.7**	**8.0**
CANADA — **Total***	**13794.2**	**6916.3**	**6877.9**

*Frontier reserves not included

National Energy Board Forecast of Crude Oil Producibility from Established Reserves at 1/1/75 (b/d)

Pool	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Northwest Territories																				
Norman Wells																				
Norman Wells	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000
Pipeline Total	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**
British Columbia																				
Blueberry – Taylor Pipelines																				
Aitken Creek – Gething	880	685	533	415	323	252	196	152	119	92	72	56	26	0	0	0	0	0	0	0
Blueberry – Debolt	1200	1096	1002	916	837	765	699	639	584	533	487	445	407	372	340	311	284	259	237	217
Inga – Inga	6200	6329	5726	5079	4504	3995	3543	3142	2787	2472	2192	1944	1724	1529	1356	1203	1067	946	839	744
Other	588	576	516	455	402	356	315	279	248	220	195	173	153	135	120	107	96	85	76	68
Pipeline Total	**8868**	**8688**	**7779**	**6866**	**6068**	**5368**	**4754**	**4214**	**3738**	**3319**	**2948**	**2620**	**2312**	**2037**	**1817**	**1622**	**1447**	**1292**	**1153**	**1030**
Trans-Prairie Pipelines Ltd.: Beatton River – Taylor																				
Beatton River – Halfway	900	790	693	609	535	469	412	362	318	279	245	215	189	166	145	128	112	96	0	0
Beatton River West – Bluesky Gething	950	817	703	605	521	448	386	332	286	246	211	182	157	135	116	100	86	74	63	54
Crush – Halfway	700	602	518	446	384	330	284	244	210	181	156	134	115	99	85	73	63	54	32	0
Currant – Halfway	250	208	174	145	121	101	84	70	59	51	0	0	0	0	0	0	0	0	0	0
Milligan Creek – Halfway	3800	3111	2547	2085	1707	1397	1144	937	767	628	514	421	344	282	231	189	154	126	103	20
Peejay – Halfway	6500	5429	4534	3787	3163	2642	2207	1843	1540	1286	1074	897	749	626	522	436	364	304	254	212
Weasel – Halfway	2500	2088	1744	1456	1216	1016	848	709	592	494	413	345	288	240	201	168	140	117	97	81
Wildmint – Halfway	600	444	329	243	180	133	99	73	54	16	0	0	0	0	0	0	0	0	0	0
Other	843	702	585	488	407	340	284	238	199	165	136	114	95	80	67	57	47	40	28	19
Pipeline Total	**17043**	**14194**	**11831**	**9869**	**8238**	**6882**	**5752**	**4812**	**4027**	**3350**	**2751**	**2310**	**1940**	**1630**	**1370**	**1153**	**970**	**814**	**580**	**389**

National Energy Board Forecast of Crude Oil Producibility from Established Reserves at 1/1/75 (b/d)

Pool	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Trans-Prairie Pipelines Ltd.: Boundary Lake – Taylor																				
Boundary Lake Unit No. 1	10000	9417	8869	8352	7866	7408	6976	6570	6187	5827	5488	5168	4867	4584	4317	4065	3828	3605	3395	3198
Boundary Lake Unit No. 2	7500	6854	6264	5725	5232	4782	4370	3994	3650	3336	3049	2786	2546	2327	2127	1944	1776	1624	1484	1356
Other	1645	1530	1423	1323	1231	1146	1067	993	925	861	802	748	697	649	606	565	527	491	458	428
Pipeline Total	**19145**	**17802**	**16556**	**15401**	**14330**	**13336**	**12414**	**11558**	**10763**	**10025**	**9340**	**8703**	**8111**	**7561**	**7050**	**6575**	**6133**	**5721**	**5339**	**4982**
British Columbia Total	**45057**	**40685**	**36167**	**32137**	**28637**	**25587**	**22922**	**20585**	**18529**	**16694**	**15040**	**13634**	**12364**	**11229**	**10239**	**9350**	**8550**	**7828**	**7073**	**6402**
Alberta																				
Bow River Pipe Lines Ltd.: Light & Medium																				
Provost – Viking CAK	10000	11000	12000	13000	13000	13000	13000	13000	12554	11591	10700	9877	9118	8416	7769	7172	6621	6111	5642	5208
Other	118	130	141	153	153	153	153	153	148	136	126	116	107	99	91	84	78	72	66	61
Pipeline Total	**10118**	**11130**	**12141**	**13153**	**13153**	**13153**	**13153**	**13153**	**12702**	**11728**	**10826**	**9994**	**9225**	**8516**	**7861**	**7257**	**6699**	**6184**	**5708**	**5269**
Bow River Pipe Lines Ltd.: Heavy																				
Bantry – Mannville A	5400	5399	5086	4556	4081	3656	3275	2934	2628	2354	2109	1889	1693	1516	1358	1217	1090	976	875	783
Countess – Upper Mannville D	6113	5393	4642	3995	3439	2960	2547	2192	1887	1624	1398	1203	1035	891	767	660	568	489	421	362
Countess – Upper Mannville H	4000	3442	2963	2550	2195	1889	1626	1399	1204	1036	892	768	661	569	489	421	362	312	268	231
Grand Forks – Lower Mannville D	2700	4800	6900	9000	9000	9000	9000	8703	7255	5940	4863	3981	3260	2669	2185	1789	1464	1199	981	803
Hays – Lower Mannville A	2300	1959	1670	1423	1212	1033	880	750	639	544	464	395	337	287	244	208	177	151	129	110
Lathom – Upper Mannville A	2500	2500	2475	2154	1799	1503	1255	1048	876	731	611	510	426	356	297	248	207	173	144	120
Taber – Mannville D	2000	2000	2000	2000	1999	1804	1477	1209	990	810	663	543	444	364	298	244	199	163	133	105
Taber South – Mannville B	2400	1964	1608	1317	1078	882	722	591	484	396	324	265	217	178	145	119	98	0	0	0
Other	14500	14479	13186	11349	9768	8407	7236	6228	5361	4614	3971	3418	2942	2532	2179	1876	1614	1389	1196	1029
Pipeline Total	**41913**	**41939**	**40532**	**38347**	**34575**	**31137**	**28022**	**25059**	**21327**	**18055**	**15299**	**12977**	**11018**	**9364**	**7967**	**6785**	**5785**	**4856**	**4151**	**3547**

National Energy Board Forecast of Crude Oil Producibility from Established Reserves at 1/1/75 (b/d)

Pool	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
BPOG Operations Ltd.																				
Chauvin – Mannville A	750	685	626	572	523	478	437	399	365	333	304	278	254	232	212	194	177	162	148	135
Chauvin South – Sparky A & B	1210	1083	971	869	779	698	625	560	501	449	402	360	323	289	259	232	208	186	167	149
Chauvin South – Sparky H	320	286	256	230	206	184	165	148	132	118	106	95	85	76	68	61	55	49	44	39
Chauvin South – Lloydminster D	330	292	259	230	204	181	160	142	126	112	99	88	78	69	61	54	48	42	38	33
Other	1595	1436	1292	1163	1047	942	848	764	688	620	558	503	453	408	368	331	299	269	243	219
Pipeline Total	**4205**	**3784**	**3406**	**3066**	**2760**	**2484**	**2237**	**2014**	**1814**	**1634**	**1472**	**1326**	**1195**	**1076**	**970**	**874**	**788**	**710**	**640**	**577**
Canadian Industrial Gas and Oil Ltd.																				
Joarcam – Viking	8000	6549	5362	4390	3594	2943	2409	1972	1615	1322	1082	886	725	594	478	0	0	0	0	0
Pipeline Total	**8000**	**6549**	**5362**	**4390**	**3594**	**2943**	**2409**	**1972**	**1615**	**1322**	**1082**	**886**	**725**	**594**	**478**	**0**	**0**	**0**	**0**	**0**
Cremona Pipeline																				
Crossfield – Cardium A	1300	1092	928	797	690	602	529	468	416	372	335	151	0	0	0	0	0	0	0	0
Harmattan East – Rundle	14000	11313	9402	7984	6896	6039	5349	4784	4314	3918	3580	3289	3036	2815	2620	2447	2293	2154	2029	1917
Harmattan Elkton – Rundle C	6660	5656	4841	4190	3662	3228	2867	2563	2305	2084	1894	1728	1583	1456	1343	1243	1154	1074	1002	937
Other	4559	3750	3150	2693	2335	2049	1816	1623	1461	1323	1206	1073	959	886	825	766	715	670	629	592
Pipeline Total	**26520**	**21813**	**18323**	**15666**	**13585**	**11920**	**10563**	**9440**	**8498**	**7699**	**7015**	**6242**	**5579**	**5158**	**4787**	**4457**	**4163**	**3899**	**3662**	**3447**
Federated Pipe Lines Ltd.																				
Carson Creek North – BHL A	4800	4900	5000	4737	4218	3771	3383	3045	2751	2492	2264	2062	1883	1724	1582	1454	1340	1257	1144	1060
Carson Creek North – BHL B	17000	18500	20000	21492	19865	17269	15013	13052	11347	9864	8576	7455	6481	5634	4898	4252	3702	3218	2798	2432
Judy Creek – BHL A	85800	79771	68660	59096	50864	43779	37681	32432	27915	24026	20680	17799	15320	13186	11349	9768	8407	7236	6228	5361
Judy Creek – BHL B	26154	23915	20791	18075	15713	13660	11876	10324	8975	7803	6783	5897	5127	4457	3874	3368	2926	2546	2213	1924
Swan Hills – BHL A & B	105000	105000	105000	102245	92856	84020	76024	68789	62243	56320	50960	46111	41723	37752	34160	30909	27967	25306	22898	20719
Swan Hills – BHL C	20800	19404	18122	16943	15856	14854	13929	13074	12282	11549	10868	10237	9650	9103	8595	8120	7672	7265	6879	6517
Swan Hills South – BHL A & B	70000	70000	70000	70000	70000	68950	60741	52280	44998	38730	33339	28692	24695	21255	18294	15746	13553	11665	10040	8641
Virginia Hills – BHL	28389	25231	22155	19454	17082	15000	13171	11566	10156	8918	7830	6876	6038	5301	4655	4088	3589	3152	2767	2430
Other	5978	5791	5507	5212	4784	4364	3872	3416	3017	2667	2360	2090	1852	1643	1460	1298	1155	1029	[illegible]	819
Pipeline Total	**363922**	**352513**	**335236**	**317256**	**291243**	**265672**	**235694**	**207983**	**183687**	**162372**	**143660**	**127221**	**112771**	**100060**	**88870**	**79013**	**70323**	**62657**	**55888**	**49907**

National Energy Board Forecast of Crude Oil Producibility from Established Reserves at 1/1/75 (b/d)

Pool	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Gibson Petroleum Company Limited																				
Bellshill Lake – Blairmore	7000	6280	5651	5100	4614	4186	3806	3469	3169	2900	2660	2444	2250	2075	1916	1773	1643	1524	1417	1318
Thompson Lake – Blairmore	550	497	450	407	368	333	301	273	247	223	202	183	165	149	135	122	111	100	90	82
Pipeline Total	**7550**	**6778**	**6102**	**5507**	**4983**	**4520**	**4108**	**3742**	**3416**	**3124**	**2862**	**2627**	**2416**	**2225**	**2052**	**1896**	**1754**	**1625**	**1508**	**1401**
Gulf Alberta Pipe Line																				
Clive – D-2A	4000	4000	4000	4000	3996	3658	3149	2710	2333	2008	1728	1487	1280	1102	948	816	702	604	520	448
Clive – D-3A	6900	6900	6900	6900	6900	6900	6900	6607	5474	4482	3669	3004	2459	2014	1648	1350	1105	904	740	606
Drumheller – D-2B	1900	1900	1900	1900	1900	1876	1604	1313	1075	880	720	590	483	395	323	265	217	177	145	119
Duhamel – D-2A	600	491	402	329	269	220	180	147	121	99	81	32	0	0	0	0	0	0	0	0
Duhamel – D-3B	950	886	728	596	488	399	327	267	219	179	147	120	98	70	0	0	0	0	0	0
Erskine – D-3	1800	1800	1800	1800	1759	1579	1413	1270	1146	1039	945	863	790	726	669	617	572	530	493	460
Fenn Big Valley – D-2A	38000	38000	35676	29332	24015	19662	16097	13179	10790	8834	7233	5922	4848	3969	3250	2660	2178	1783	1460	1195
Hussar – Glauconitic A	3100	3033	2716	2409	2137	1895	1681	1491	1322	1172	1040	922	818	725	643	570	506	449	398	353
Joffre – D-2	1750	2000	2250	2500	2500	2476	2278	2061	1865	1687	1527	1381	1250	1131	1023	926	838	758	686	620
Stettler – D-2A	1400	1217	1058	919	799	695	604	525	456	397	345	300	260	226	197	171	84	0	0	0
Stettler – D-3A	2900	2900	2900	2900	2900	2823	2368	1939	1587	1299	1064	871	713	584	478	391	320	262	214	170
West Drumheller – D-2A	3000	2814	2423	2086	1795	1545	1330	1144	985	848	729	628	540	465	209	0	0	0	0	0
Other	18876	18775	17867	15851	14082	12451	10800	9298	7794	6528	5475	4591	3856	3248	2674	2212	1857	1557	1326	1131
Pipeline Total	**85176**	**84718**	**80623**	**71524**	**63544**	**56186**	**48734**	**41957**	**35173**	**29457**	**24708**	**20716**	**17401**	**14660**	**12067**	**9982**	**8383**	**7029**	**5987**	**5105**
Husky Pipeline Ltd.																				
Lloydminster – Sparky C and GP A	883	805	728	659	596	539	488	441	399	361	327	296	268	242	219	198	179	162	145	0
Lloydminster – Sparky and GP C	1800	1800	1761	1616	1477	1350	1233	1127	1030	941	860	786	719	657	600	548	501	458	419	382
Wainwright – Wainwright	6481	6038	5463	4943	4473	4047	3662	3313	2998	2713	2454	2221	2009	1818	1645	1488	1347	1219	1103	998
Other	1251	1180	1086	986	894	811	735	667	604	548	497	451	409	371	336	305	277	251	227	186
Pipeline Total	**10416**	**9824**	**9039**	**8205**	**7441**	**6748**	**6120**	**5550**	**5033**	**4565**	**4140**	**3755**	**3406**	**3089**	**2802**	**2541**	**2305**	**2091**	**1895**	**1569**

National Energy Board Forecast of Crude Oil Producibility from Established Reserves at 1/1/75 (b/d)

Pool	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
The Imperial Pipe Line Company, Limited: Ellerslie																				
Acheson – D-3A	16000	16000	16000	16000	14896	11688	9102	7089	5521	4299	3348	2607	2031	1581	1231	959	747	581	448	0
Golden Spike – D-3A	48400	43219	32705	24717	18681	14119	10671	8064	6095	4606	3481	2631	1988	1503	1136	858	648	490	89	0
Other	11587	10655	8763	7326	6041	4643	3557	2726	2090	1602	1229	942	723	555	426	327	251	192	96	0
Pipeline Total	**75987**	**69875**	**57468**	**48044**	**39619**	**30450**	**23331**	**17880**	**13706**	**10509**	**8059**	**6182**	**4743**	**3640**	**2794**	**2145**	**1647**	**1265**	**634**	**0**
The Imperial Pipe Line Company, Limited: Excelsior																				
Excelsior – D-2	2900	2398	1983	1640	1356	1121	927	766	634	524	433	358	296	245	202	167	138	114	79	0
Fairydell Bon Accord – D-3A	1800	1533	1307	1113	949	808	689	587	500	426	363	309	263	224	191	163	139	118	101	7
Other	545	456	382	319	267	224	187	157	131	110	92	77	65	54	45	38	32	27	20	0
Pipeline Total	**5245**	**4388**	**3672**	**3073**	**2573**	**2154**	**1804**	**1511**	**1266**	**1061**	**889**	**746**	**625**	**524**	**440**	**369**	**310**	**260**	**201**	**7**
The Imperial Pipe Line Company, Limited: Leduc																				
Leduc Woodbend – D-2A	1000	769	625	526	454	400	357	322	246	0	0	0	0	0	0	0	0	0	0	0
Leduc Woodbend – D-3A	17000	13779	11169	9054	7339	5948	4822	3908	3168	2568	2081	1687	1367	1108	898	728	590	441	0	0
Other	2222	1796	1456	1182	962	783	639	522	421	317	257	208	168	136	110	89	72	54	0	0
Pipeline Total	**20222**	**16345**	**13251**	**10763**	**8755**	**7132**	**5818**	**4753**	**3836**	**2885**	**2338**	**1895**	**1536**	**1245**	**1009**	**818**	**663**	**495**	**0**	**0**

National Energy Board Forecast of Crude Oil Producibility from Established Reserves at 1/1/75 (b/d)

Pool	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
The Imperial Pipe Line Company, Limited: Redwater																				
Redwater – D-3	145000	128243	98886	76246	58789	45330	34951	26949	20779	16022	12353	9525	7344	5663	4366	3366	2595	2001	1543	1190
Pipeline Total	**145000**	**128243**	**98886**	**76246**	**58789**	**45330**	**34951**	**26949**	**20779**	**16022**	**12353**	**9525**	**7344**	**5663**	**4366**	**3366**	**2595**	**2001**	**1543**	**1190**
Murphy Milk River Pipe Line																				
Coutts – Total	1050	1041	952	852	764	684	613	549	492	440	394	353	316	283	254	227	204	182	163	146
Red Coulee – Total	200	177	157	139	123	109	97	86	76	67	60	53	47	42	37	33	25	0	0	0
Manyberries – Total	700	688	650	612	576	543	511	481	453	427	402	378	356	336	316	298	280	264	248	234
Other	1233	1129	1022	924	836	757	685	619	560	507	459	415	375	340	307	278	252	228	206	186
Pipeline Total	**3183**	**3036**	**2781**	**2529**	**2301**	**2094**	**1907**	**1737**	**1583**	**1443**	**1316**	**1201**	**1097**	**1002**	**915**	**837**	**762**	**675**	**619**	**567**
Peace River Oil Pipe Line Co. Ltd.																				
Goose River – BHL A	6086	5678	5253	4867	4515	4195	3902	3634	3389	3163	2956	2766	2591	2429	2279	2141	2013	1894	1784	1682
Kaybob – BHL A	17000	17000	16995	15724	13670	11884	10331	8982	7808	6788	5901	5130	4460	3877	3371	2930	2547	2214	1925	1674
Kaybob South – Triassic A	15500	15750	15922	14568	12920	11459	10163	9014	7995	7091	6289	5578	4947	4387	3891	3451	3061	2715	2408	2135
Nipisi – Gilwood A	17160	17160	17160	17154	15859	13787	11986	10420	9058	7875	6846	5952	5174	4498	3910	3399	2955	2569	2233	1942
Simonette – D-3	11333	11388	11444	11405	9962	8321	6950	5805	4849	4050	3383	2825	2360	1971	1646	1375	1148	959	801	660
Snipe Like – BHL	7500	7500	7345	6923·	6520	6140	5782	5446	5129	4830	4549	4284	4034	3799	3578	3370	3173	2988	2814	2650
Sturgeon Lake – D-3	5997	5153	3894	2943	2224	1681	1270	960	725	548	414	211	0	0	0	0	0	0	0	0
Sturgeon Lake South – D-3	20000	20000	20000	20000	20000	20000	19105	16503	14204	12226	10523	9057	7795	6709	5775	4970	4278	3682	3169	2728
Utikuma – KR Sand A	4664	4299	3890	3520	3185	2882	2608	2359	2135	1932	1748	1581	1431	1295	1171	1060	959	868	785	710
Other	19454	19211	18837	17950	16425	14853	13328	11669	10221	8966	7877	6911	6062	5355	4736	4196	3722	3307	2943	2623
Pipeline Total	**124695**	**123141**	**120743**	**115058**	**105285**	**95205**	**85431**	**74796**	**65517**	**57473**	**50489**	**44299**	**38857**	**34324**	**30362**	**26896**	**23861**	**21201**	**18867**	**16817**

National Energy Board Forecast of Crude Oil Producibility from Established Reserves at 1/1/75 (b/d)

Pool	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Pembina Pipe Line Ltd.																				
Pembina – Cardium	87000	76879	68696	61958	56323	51548	47455	43912	40819	38096	35684	33534	31606	29869	28296	26867	25562	24367	23269	22257
Pembina – Keystone Belly River B	10200	10200	9745	8819	7980	7220	6533	5911	5349	4840	4379	3962	3585	3244	2935	2656	2403	2174	1967	1780
Willesden Green – Cardium A	9800	9731	9057	8321	7672	7095	6582	6122	5708	5335	4998	4692	4412	4158	3924	3710	3513	3331	3162	3007
Other	6968	6304	5698	5151	4687	4289	3944	3643	3378	3143	2934	2747	2579	2427	2289	2164	2050	1945	1849	1761
Pipeline Total	**113968**	**103115**	**93197**	**84250**	**76662**	**70154**	**64515**	**59589**	**55255**	**51416**	**47997**	**44936**	**42184**	**39698**	**37446**	**35397**	**33529**	**31818**	**30249**	**28806**
Rainbow Pipe Line Company, Ltd.																				
Mitsue – Gilwood A	50000	50000	50000	50000	48473	43573	39034	34968	31325	28062	25139	22520	20175	18073	16190	14504	12993	11639	10427	9341
Nipisi – Gilwood A	34840	34840	34840	34830	32233	28022	24361	21179	18412	16006	13915	12097	10517	9143	7948	6910	6007	5222	4540	3947
Rainbow – KR A	7500	7500	7500	7500	7500	7500	7500	7500	7500	7500	7500	7500	7165	6302	5534	4859	4267	3747	3290	2889
Rainbow – KR B	27000	27000	27000	27000	26227	22820	19641	16905	14551	12524	10779	9278	7985	6873	5916	5091	4382	3772	3246	2794
Rainbow – KR F	18000	18000	18000	18000	17973	16363	14084	12122	10433	8980	7729	6652	5726	4928	4242	3651	3142	2704	2328	2003
Rainbow – KR AA	9700	13000	13000	13000	13000	13000	13000	12881	11451	9856	8483	7301	6284	5409	4655	4007	3449	2968	2555	2199
Rainbow South – KR A	3700	3700	3700	3609	3149	2710	2333	2008	1728	1487	1280	1102	948	816	702	604	520	448	385	331
Rainbow South – KR B	5500	5500	5500	5500	5500	5480	4972	4322	3758	3267	2840	2469	2146	1866	1622	1410	1226	1065	926	805
Rainbow South – KR E	4500	4500	4500	4500	4492	4087	3518	3028	2606	2243	1930	1661	1430	1231	1059	912	785	675	581	500
Virgo – Total	10300	10300	10300	10260	9532	8625	7804	7061	6389	5781	5231	4733	4283	3875	3506	3173	2871	2597	2350	2126
Zama – Total	19000	19000	18829	17324	15676	14184	12834	11613	10508	9508	8603	7784	7043	6373	5766	5218	4721	4272	3865	3497
Other	44388	45159	45119	44735	42921	38859	34822	31203	27717	24576	21824	19410	17216	15157	13348	11759	10363	9136	8058	7109
Pipeline Total	**234428**	**238499**	**238288**	**236261**	**226680**	**205228**	**183907**	**164795**	**146382**	**129794**	**115258**	**102513**	**90923**	**80051**	**70494**	**62102**	**54730**	**48251**	**42556**	**37547**
Rangeland Pipe Line Company Limited																				
Ferrier – Cardium E	2000	1943	1835	1739	1652	1573	1501	1436	1375	1320	1268	1221	1177	1135	1097	1061	1027	995	965	937
Gilby – Jurassic B	1150	1487	1825	2162	2500	2289	2105	1943	1800	1672	1558	1455	1363	1279	1203	1134	1070	1013	959	910
Gilby – Viking A	700	628	565	511	463	420	383	350	320	294	270	249	230	212	197	183	170	158	147	138
Innisfail – D-3	12000	12000	11995	10745	8797	7202	5897	4828	3952	3236	2649	2169	1776	1454	1190	974	798	653	534	437
Joffre – D-2	3500	4000	4500	5000	5000	4997	4708	4260	3855	3488	3156	2855	2584	2338	2115	1914	1732	1567	1418	1283
Medicine River – Glauconitic A	1600	1600	1600	1579	1457	1331	1217	1112	1016	929	849	776	709	648	592	541	494	452	413	377
Medicine River – Jurassic A	1500	1474	1345	1217	1101	996	902	816	738	668	604	547	495	447	405	366	331	300	271	245
Medicine River – Jurassic D	1450	1450	1450	1450	1425	1316	1214	1126	1048	980	919	864	815	771	731	695	662	631	603	577
Sundre – Rundle A	3700	3201	2797	2465	2189	1957	1759	1590	1445	1318	1208	1110	1024	948	880	819	764	714	669	629
Willesden Green – Cardium A	4200	4200	4200	4165	3870	3556	3279	3033	2813	2617	2440	2281	2137	2006	1887	1778	1678	1587	1502	1425
Other	19685	19800	19881	19212	17616	15874	14219	12688	11370	10229	9239	8377	7622	6960	6377	5862	5405	4998	4635	4310
Pipeline Total	**51485**	**51785**	**51996**	**50249**	**46074**	**41517**	**37189**	**33186**	**29737**	**26754**	**24165**	**21909**	**19936**	**18204**	**16679**	**15331**	**14136**	**13072**	**12123**	**11274**

National Energy Board Forecast of Crude Oil Producibility from Established Reserves at 1/1/75 (b/d)

Pool	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Texaco Exploration Canada Ltd.																				
Bonnie Glen – D-3A	100000	100000	98141	79149	60420	46124	35210	26878	20518	15663	11957	9127	6968	5319	4060	3099	2366	1806	1372	1052
Glen Park – D-3A	3700	3700	3700	3700	3278	2503	1911	1459	1113	850	649	495	378	288	220	168	128	98	74	57
Westerose – D-3	22000	22000	22000	22000	22000	21941	18762	14612	11380	8862	6902	5375	4186	3260	2539	1977	1540	1199	934	727
Wizard Lake – D-3A	63000	63000	63000	63000	55317	42228	32236	24608	18785	14340	10947	8357	6379	4870	3717	2838	2166	1653	1262	[illegible]
Other	523	523	518	465	390	312	244	187	143	110	84	64	49	38	29	22	17	13	10	7
Pipeline Total	**189223**	**189223**	**187359**	**168314**	**141408**	**113110**	**88365**	**67746**	**51942**	**39827**	**30540**	**23420**	**17962**	**13776**	**10567**	**8106**	**6218**	**4770**	**3660**	**2808**
Trans-Prairie Pipelines Ltd.: Boundary Lake South																				
Boundary Lake South – Triassic E	4050	4038	3785	3459	3161	2889	2641	2413	2205	2016	1842	1683	1539	1406	1285	1174	1073	981	896	819
Other	737	735	689	630	576	526	481	439	401	367	335	306	280	256	234	214	195	178	163	149
Pipeline Total	**4787**	**4774**	**4475**	**4090**	**3738**	**3416**	**3122**	**2853**	**2607**	**2383**	**2178**	**1990**	**1819**	**1662**	**1519**	**1388**	**1269**	**1160**	**1060**	**969**
Twining Pipeline Division																				
Twining – Rundle A and LM A	4400	4845	4525	4054	3631	3253	2914	2610	2338	2095	1877	1681	1506	1349	1208	1082	970	869	778	697
Twining North – Rundle	616	563	499	443	393	348	309	274	243	215	191	169	150	133	118	104	93	63	[illegible]	0
Pipeline Total	**5016**	**5408**	**5025**	**4497**	**4024**	**3602**	**3223**	**2885**	**2582**	**2311**	**2068**	**1851**	**1656**	**1482**	**1327**	**1187**	**1063**	**932**	**778**	**697**
Valley Pipe Line																				
Turner Valley – Rundle	3000	3000	3000	3000	2921	2653	2401	2172	1965	1778	1609	1456	1317	1192	1078	976	883	799	[illegible]	654
Pipeline Total	**3000**	**3000**	**3000**	**3000**	**2921**	**2653**	**2401**	**2172**	**1965**	**1778**	**1609**	**1456**	**1317**	**1192**	**1078**	**976**	**883**	**799**	**723**	**654**

National Energy Board Forecast of Crude Oil Producibility from Established Reserves at 1/1/75 (b/d)

Pool	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Truck and Tank Car																				
Cessford – Total	2800	2458	2158	1895	1664	1461	1283	1127	989	869	763	670	588	516	453	398	349	307	58	0
Other Heavy	2300	2287	2161	2015	1878	1751	1633	1522	1420	1324	1234	1151	1073	1000	933	869	811	756	705	657
Light & Medium – Total	1500	1500	1456	1345	1241	1146	1058	976	901	832	768	709	654	604	557	515	475	438	405	374
Pipeline Total	**6600**	**6246**	**5776**	**5256**	**4785**	**4359**	**3975**	**3626**	**3311**	**3025**	**2765**	**2530**	**2316**	**2121**	**1944**	**1783**	**1636**	**1502**	**1168**	**1031**
Alberta Total	**1540669**	**1486136**	**1396692**	**1288751**	**1158502**	**1021178**	**890989**	**775360**	**673745**	**586647**	**513101**	**450207**	**396061**	**349337**	**308804**	**273517**	**243511**	**217263**	**193630**	**173199**
Saskatchewan																				
Husky Pipeline Ltd. & Murphy Oil Company Ltd.																				
Aberfeldy – Sparky, Aberfeldy Unit	4660	4051	3521	3061	2661	2314	2011	1748	1520	1321	1149	1067	0	0	0	0	0	0	0	0
South Aberfeldy – Sparky Vol. Unit	1870	1625	1413	1228	1068	928	807	701	610	530	461	400	348	302	263	99	0	0	0	0
Dulwich – Sparky	770	710	656	605	559	516	476	439	406	374	345	319	294	272	251	231	214	177	0	0
Epping – Sparky, Non-Unit	2070	1794	1528	1302	1110	945	806	686	585	498	425	362	212	0	0	0	0	0	0	0
South Epping Unit No. 1 – Sparky	2370	2123	1901	1703	1526	1367	1224	1097	983	880	788	706	633	567	508	455	407	365	327	293
S.W. Epping Sparky Vol. Unit No. 1	959	907	820	742	672	608	550	497	450	407	368	333	301	273	247	223	127	0	0	0
Furness – Sparky	935	765	626	513	420	344	281	230	188	154	126	69	0	0	0	0	0	0	0	0
Golden Lake North – W & Spky, Vol. U	2740	2288	1911	1596	1333	1114	930	777	649	542	452	378	315	94	0	0	0	0	0	0
Golden Lake North – Waseca Non U	457	377	309	253	207	169	139	113	93	70	0	0	0	0	0	0	0	0	0	0
Golden Lake South – Sparky	540	475	409	352	303	260	224	193	166	143	123	94	0	0	0	0	0	0	0	0
Golden Lake South – Waseca	1768	1499	1227	1005	822	673	551	451	369	302	247	119	0	0	0	0	0	0	0	0
Gully Lake – Waseca, Vol. Unit No. 1	820	705	607	522	450	387	333	286	246	212	87	0	0	0	0	0	0	0	0	0
Gully Lake – Waseca, Non-Unit	499	447	365	299	245	200	164	134	108	0	0	0	0	0	0	0	0	0	0	0
Lashburn – Waseca, Vol. Unit	870	726	606	506	423	353	295	246	206	0	0	0	0	0	0	0	0	0	0	0
Lone Rock – Sparky	270	241	216	194	173	155	143	0	0	0	0	0	0	0	0	0	0	0	0	0
Other	5080	5039	4335	3734	3220	2780	2404	2045	1770	1462	1230	1036	566	406	341	271	201	145	87	78
Pipeline Total	**27410**	**23779**	**20460**	**17624**	**15198**	**13121**	**11345**	**9653**	**8355**	**6903**	**5808**	**4889**	**2673**	**1916**	**1611**	**1282**	**950**	**688**	**415**	**371**

National Energy Board Forecast of Crude Oil Producibility from Established Reserves at 1/1/75
(b/d)

Pool	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Bow River Pipe Lines Ltd.																				
Coleville – Bakken	4527	3988	3443	2977	2580	2239	1947	1696	1480	1294	1132	993	872	767	675	596	526	38	0	0
Dodsland – Viking, Gleneath Unit	1300	1212	1133	1060	993	931	874	822	773	728	687	648	612	579	548	519	492	467	444	422
Dodsland – Vik, Eagle Lk Vol. Unit	1650	1554	1463	1379	1299	1224	1154	1087	1025	967	911	860	811	765	722	681	643	607	573	541
North Hoosier – Bakken, Vol. Unit	835	789	735	685	639	596	556	518	483	450	420	391	365	340	317	296	276	257	240	223
North Hoosier – Bsl Blair, Vol. Unit	592	535	474	420	373	331	293	260	230	204	181	161	142	126	112	99	88	27	0	0
Smiley Dewar – Viking	2300	2166	2040	1922	1812	1708	1610	1519	1432	1351	1275	1203	1136	1073	1013	957	904	854	807	763
Other	4000	4000	3994	3699	3281	2910	2581	2289	2030	1800	1597	1416	1256	1114	988	876	777	689	611	542
Pipeline Total	**15205**	**14246**	**13285**	**12147**	**10979**	**9942**	**9018**	**8194**	**7457**	**6798**	**6207**	**5676**	**5198**	**4767**	**4378**	**4027**	**3709**	**2942**	**2676**	**2493**
South Saskatchewan Pipe Line Company																				
Battrum – Roseray, Unit No. 1	2520	2373	2235	2104	1982	1866	1758	1655	1559	1468	1383	1302	1226	1155	1087	1024	964	908	855	805
Cantuar Main – Cantuar, Unit	2000	1809	1637	1481	1340	1213	1097	993	898	813	735	665	602	545	493	446	403	365	330	299
Dollard – Upper Shaunavon, Unit	9000	7368	6032	4939	4043	3310	2710	2219	1817	1487	1218	997	816	668	547	489	0	0	0	0
Fosterton – Roseray, Main Unit	4400	4021	3675	3358	3069	2805	2564	2343	2141	1957	1788	1634	1494	1365	1248	1140	1042	952	870	795
Gull Lake N. – Up. Shaun, Unit	1800	1505	1263	1063	898	760	645	549	468	401	343	295	254	219	140	0	0	0	0	0
Instow – Upper Shaunavon, Unit	4700	4169	3699	3283	2914	2588	2299	2043	1816	1614	1435	1277	1136	1011	900	801	714	636	567	505
Main Success – Roseray, Unit	900	751	627	524	438	365	305	255	213	178	148	124	103	22	0	0	0	0	0	0
North Premier – Roseray, Unit No. 3	1680	1308	1018	793	618	481	374	291	227	177	137	107	32	0	0	0	0	0	0	0
Rapdan – Upper Shaunavon, Unit	1900	1736	1587	1450	1325	1211	1107	1011	924	845	772	705	645	589	538	492	450	411	376	343
South Success – Roseray, Unit	1600	1447	1309	1185	1072	970	878	794	718	650	588	532	481	436	394	357	323	292	264	239
Suffield – Upr Shaun, Unit No. 2	1092	1008	912	825	746	675	611	553	500	452	409	370	335	303	274	248	224	203	184	166
Verlo – Roseray, Unit	2300	2123	1959	1809	1670	1541	1423	1313	1212	1119	1033	954	880	812	750	692	639	590	544	503
Other	27342	24297	20913	18000	15492	13334	11477	9878	8502	7318	6298	5421	4666	4016	3456	2975	2560	2204	1897	1632
Pipeline Total	**61234**	**53921**	**46872**	**40820**	**35613**	**31126**	**27253**	**23903**	**21002**	**18484**	**16295**	**14389**	**12676**	**11146**	**9833**	**8668**	**7324**	**6565**	**5891**	**5292**

National Energy Board Forecast of Crude Oil Producibility from Established Reserves at 1/1/75 (b/d)

Pool	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Westpur Pipe Line Company – Midale Medium																				
Benson – Midale, Unit	1090	1006	928	857	791	730	674	622	574	530	489	452	417	385	355	328	303	279	258	238
Flat Lake – Ratcliffe, Vol. Unit 1	1500	1384	1278	1179	1089	1005	928	856	790	730	673	622	574	530	489	451	417	384	355	328
Innes – Frobisher	1450	1280	1143	1030	935	854	785	726	673	627	587	550	518	488	462	438	416	396	377	360
Lost Horse Hill – Frob. Vol. Unit 1	1750	1536	1349	1184	1040	913	802	704	618	543	476	418	367	322	283	248	218	191	168	148
Midale – Central Midale, Unit	8900	8215	7584	7000	6462	5965	5507	5083	4692	4332	3999	3691	3407	3145	2903	2680	2474	2284	2108	1946
Midale – Central Midale, Non-Unit	820	720	632	555	487	428	375	330	289	254	36	0	0	0	0	0	0	0	0	0
Sherwood – Frobisher	1130	1022	925	837	757	685	620	561	507	459	415	376	340	307	278	252	228	206	186	169
Viewfield – Frobisher	1750	1744	1634	1493	1364	1247	1140	1041	952	870	795	726	664	607	554	507	463	423	387	353
Weyburn – Midale, Unit	23000	21660	20399	19211	18092	17038	16046	15112	14232	13403	12622	11887	11195	10543	9929	9351	8806	8293	7810	7355
Weyburn – Midale, Non-Unit	910	807	715	634	563	499	442	392	348	309	274	243	215	191	169	150	133	118	104	42
Other	7076	6588	6121	5685	5284	4913	4571	4254	3961	3690	3408	3173	2961	2764	2581	2410	2252	2104	1967	1830
Pipeline Total	**49376**	**45967**	**42712**	**39671**	**36869**	**34283**	**31894**	**29686**	**27643**	**25750**	**23779**	**22142**	**20662**	**19287**	**18008**	**16819**	**15713**	**14684**	**13725**	**12774**
Westpur Pipe Line Company – S.E. Sask. Light																				
Alida East – Alida, Unit	530	489	451	416	384	355	327	302	279	257	238	219	202	187	172	159	147	136	125	115
Carnduff – Midale, East Unit	1000	904	818	740	670	606	548	496	449	298	0	0	0	0	0	0	0	0	0	0
Elmore – Frobisher	1200	1085	982	888	804	727	658	595	539	487	441	399	361	327	295	267	242	219	198	179
Ingoldsby – Frob., Vol. Unit	1250	1104	987	890	809	740	681	630	586	547	512	481	454	429	406	386	367	350	334	319
Kenosee – Tilston, Vol. Unit	2000	1721	1481	1275	1097	944	813	699	602	518	446	384	330	284	244	210	181	156	43	0
Parkman – Tilston Souris Valley	1430	1255	1102	968	850	746	655	575	505	443	389	342	300	4	0	0	0	0	0	0
Queensdale East – Frob. Non-Unit	2800	2559	2338	2137	1953	1785	1631	1491	1362	1245	1138	1040	950	869	794	725	663	606	554	506
Rosebank – Frob. Vol. Unit 1	1950	1572	1299	1094	937	813	713	632	564	507	459	418	382	351	324	300	279	260	243	228
Steelman – Midale, Unit IA	4700	4338	4005	3697	3412	3150	2908	2684	2478	2287	2111	1949	1799	1661	1533	1415	1306	1206	1113	1027
Steelman – Midale, Unit II	3600	3290	3006	2748	2511	2295	2097	1917	1752	1601	1463	1337	1222	1117	1021	933	852	779	712	651
Steelman – Midale, Unit IV	3100	2833	2589	2366	2162	1976	1806	1651	1508	1379	1260	1151	1052	962	879	803	734	671	613	560
Steelman – Midale, Unit VI	3900	3458	3067	2720	2413	2140	1898	1683	1493	1324	1174	1041	924	819	726	644	571	507	449	398
Willmar – Frobisher Alida, Non-Unit	2000	1791	1605	1437	1288	1153	1033	926	829	743	665	596	534	478	428	384	344	308	258	0
Workman – Frobisher, Vol. Unit No. 1	1410	1250	1109	983	872	773	686	608	539	478	424	376	334	296	262	233	206	183	162	144
Other	24595	22034	19795	17820	16069	14509	13116	11868	10749	9658	8547	7760	7051	6205	5650	5151	4699	4289	3832	3292
Pipeline Total	**55465**	**49690**	**44640**	**40187**	**36237**	**32720**	**29578**	**26765**	**24241**	**21779**	**19274**	**17500**	**15902**	**13993**	**12741**	**11616**	**10597**	**9673**	**8642**	**7425**
Saskatchewan Total	**208693**	**187605**	**167972**	**150451**	**134899**	**121194**	**109090**	**98203**	**88699**	**79716**	**71364**	**64598**	**57112**	**51111**	**46573**	**42414**	**38294**	**34553**	**31350**	**28356**

National Energy Board Forecast of Crude Oil Producibility
from Established Reserves at 1/1/75
(b/d)

Pool	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Manitoba																				
Trans-Prairie Pipelines Ltd.																				
Daly – Mississippian	1300	1176	1064	963	871	788	713	645	584	528	478	432	391	354	320	290	262	237	214	151
Routledge – Mississippian	950	851	762	682	611	548	491	439	394	352	316	283	253	227	203	182	163	146	131	117
North Virden Scallion – Mississippian	6100	5631	5198	4798	4429	4088	3774	3484	3216	2969	2740	2530	2335	2156	1990	1837	1696	1565	1445	1334
Virden Roselea – Mississippian	3396	3228	2980	2751	2539	2344	2164	1997	1844	1702	1571	1450	1339	1236	1141	1053	972	897	828	765
Other	896	830	763	701	644	592	545	501	460	423	389	358	329	303	278	256	236	217	199	180
Pipeline Total	12643	11717	10768	9897	9097	8363	7688	7068	6499	5977	5496	5055	4649	4277	3934	3619	3330	3064	2819	2548
Manitoba Total	12643	11717	10768	9897	9097	8363	7688	7068	6499	5977	5496	5055	4649	4277	3934	3619	3330	3064	2819	2548
Ontario																				
Ontario Total	1840	1682	1540	1412	1295	1190	1094	1007	928	856	791	731	676	626	580	538	499	464	431	401
Canada Total	1811903	1730826	1616141	1485649	1335432	1180513	1034785	905225	791404	692892	608793	537227	473865	419582	373132	332440	297186	266174	238306	213909

Table 1

Parties Which Provided Demand Forecasts

British Columbia Energy Commission

Government of Saskatchewan

Gulf Oil Canada Limited

Husky Oil Operations Ltd.

Imperial Oil Limited

Ministry of Energy for Ontario (discussion paper only)

Murphy Oil Company Ltd.

Nova Scotia Energy Council

Ontario Hydro

PanCanadian Petroleum Limited (discussion only)

Petrosar Limited

Shell Canada Limited

Standard Oil Company of British Columbia Limited

Sun Oil Company Limited

Texaco Canada Limited

Table 2
NEB Forecast of
Petroleum Product Demand
Total Canada
With and Without Conservation
Mb/d

With Conservation	1974	1975	1976	1977	1980	1985	1990	1994
Motor Gasoline	567.1	580.6	589.8	599.5	636.6	716.3	821.1	921.6
Light Fuel Oil, Kerosene and Stove Oil	329.7	328.5	330.0	328.7	335.2	356.8	380.5	394.7
Diesel Fuel Oil	186.4	193.7	202.7	211.9	243.1	299.5	369.0	437.0
Heavy Fuel Oil	294.9	311.5	330.3	369.8	401.6	444.4	494.7	551.9
Petrochemical Feedstock	40.1	40.2	49.2	80.5	141.1	187.2	231.3	241.9
Other Products	180.6	188.6	197.3	204.3	230.8	285.1	352.2	418.4
Total All Products	**1598.8**	**1643.1**	**1699.3**	**1794.7**	**1988.4**	**2289.3**	**2648.8**	**2965.5**
Without Conservation								
Total All Products	**1598.8**	**1664.7**	**1739.8**	**1861.1**	**2116.0**	**2517.3**	**2977.5**	**3410.5**

Table 3
NEB Forecast of
Petroleum Product Demand
West of the Ottawa Valley Line
With and Without Conservation
Mb/d

With Conservation	1974	1975	1976	1977	1980	1985	1990	1994
Motor Gasoline	367.4	376.0	382.2	389.0	412.8	464.7	532.3	597.9
Light Fuel Oil, Kerosene and Stove Oil	137.9	136.5	136.4	134.8	134.2	138.5	141.8	142.9
Diesel Fuel Oil	122.3	126.9	132.8	138.9	158.9	195.4	240.1	283.6
Heavy Fuel Oil	86.5	104.6	103.7	123.0	135.8	153.6	157.5	169.1
Petrochemical Feedstock	22.9	23.0	24.0	55.3	114.5	152.5	188.5	191.0
Other Products	113.0	117.8	122.9	127.0	142.5	174.2	212.8	251.6
Total All Products	**850.0**	**884.8**	**902.0**	**968.0**	**1098.7**	**1278.9**	**1473.0**	**1636.1**
Without Conservation								
Total All Products	**850.0**	**896.4**	**924.2**	**1003.5**	**1167.9**	**1401.7**	**1654.8**	**1880.5**

Table 4
NEB Forecast of
Petroleum Product Demand
East of the Ottawa Valley Line
With and Without Conservation
Mb/d

With Conservation	1974	1975	1976	1977	1980	1985	1990	1994
Motor Gasoline	199.7	204.6	207.6	210.5	223.8	251.6	288.8	323.7
Light Fuel Oil, Kerosene and Stove Oil	191.8	192.0	193.6	193.9	201.0	218.3	238.7	251.8
Diesel Fuel Oil	64.1	66.8	69.9	73.0	84.2	104.1	128.9	153.4
Heavy Fuel Oil	208.4	206.9	226.6	246.8	265.8	290.8	337.2	382.8
Petrochemical Feedstock	17.2	17.2	25.2	25.2	26.6	34.7	42.8	50.9
Other Products	67.6	70.8	74.4	77.3	88.3	110.9	139.4	166.8
Total All Products	**748.8**	**758.3**	**797.3**	**826.7**	**889.7**	**1010.4**	**1175.8**	**1329.4**
Without Conservation								
Total All Products	**748.8**	**768.3**	**815.6**	**857.6**	**948.1**	**1115.6**	**1322.7**	**1530.0**

Table 5
NEB Forecast of
Petroleum Product Demand
Atlantic Provinces
With and Without Conservation
Mb/d

With Conservation	1974	1975	1976	1977	1980	1985	1990	1994
Motor Gasoline	48.7	49.9	50.6	51.3	54.6	61.6	71.0	79.7
Light Fuel Oil, Kerosene and Stove Oil	59.1	59.9	61.2	61.8	66.1	76.1	87.5	96.1
Diesel Fuel Oil	23.6	24.7	25.5	26.6	30.5	37.1	45.2	53.0
Heavy Fuel Oil	74.6	74.3	92.5	110.3	117.5	114.4	124.9	140.0
Petrochemical Feedstock	0.5	0.5	0.5	0.5	0.6	0.7	0.8	0.9
Other Products	15.0	15.7	16.7	17.4	20.3	26.2	34.0	41.6
Total All Products	**221.5**	**225.0**	**247.0**	**267.9**	**289.6**	**316.1**	**363.4**	**411.3**
Without Conservation								
Total All Products	**221.5**	**227.7**	**252.0**	**276.7**	**305.1**	**348.0**	**403.4**	**465.6**

Table 6
NEB Forecast of
Petroleum Product Demand
Quebec
With and Without Conservation
Mb/d

With Conservation	1974	1975	1976	1977	1980	1985	1990	1994
Motor Gasoline	133.5	136.7	138.7	140.6	149.4	167.8	192.5	215.6
Light Fuel Oil, Kerosene and Stove Oil	118.2	117.8	118.0	117.9	120.7	127.6	136.2	140.7
Diesel Fuel Oil	36.4	37.8	39.9	41.8	48.3	60.3	75.3	90.3
Heavy Fuel Oil	121.3	120.2	121.8	124.4	135.0	160.4	192.8	220.3
Petrochemical Feedstock	16.7	16.7	24.7	24.7	26.0	34.0	42.0	50.0
Other Products	48.6	50.9	53.3	55.3	62.9	78.3	97.5	115.9
Total All Products	**474.7**	**480.1**	**496.4**	**504.7**	**542.3**	**628.4**	**736.3**	**832.8**
Without Conservation								
Total All Products	**474.7**	**486.6**	**508.4**	**524.5**	**580.8**	**694.0**	**832.0**	**963.8**

Table 7
NEB Forecast of
Petroleum Product Demand
Ontario
With and Without Conservation
Mb/d

With Conservation	1974	1975	1976	1977	1980	1985	1990	1994
Motor Gasoline	206.9	212.0	215.9	219.4	232.6	261.0	298.1	334.0
Light Fuel Oil, Kerosene and Stove Oil	109.1	108.0	108.0	106.8	106.4	110.0	112.3	113.1
Diesel Fuel Oil	42.9	44.8	46.8	49.2	56.8	71.0	88.6	105.1
Heavy Fuel Oil	65.2	84.3	83.6	103.0	115.3	131.0	131.2	141.7
Petrochemical Feedstock	21.9	22.0	23.0	54.3	88.5	90.5	126.0	128.0
Other Products	53.8	56.3	58.9	61.0	69.1	85.6	105.9	125.7
Total All Products	**499.8**	**527.4**	**536.2**	**593.7**	**668.7**	**749.1**	**862.1**	**947.6**
Without Conservation								
Total All Products	**499.8**	**534.7**	**549.2**	**614.8**	**710.1**	**821.3**	**968.2**	**1090.2**

Table 8
NEB Forecast of
Petroleum Product Demand
Ottawa Valley
With and Without Conservation
Mb/d

With Conservation	**1974**	**1975**	**1976**	**1977**	**1980**	**1985**	**1990**	**1994**
Motor Gasoline	17.5	18.0	18.3	18.6	19.8	22.2	25.3	28.4
Light Fuel Oil, Kerosene and Stove Oil	14.5	14.3	14.4	14.2	14.2	14.6	15.0	15.0
Diesel Fuel Oil	4.1	4.3	4.5	4.6	5.4	6.7	8.4	10.1
Heavy Fuel Oil	12.5	12.4	12.3	12.1	13.3	16.0	19.5	22.5
Petrochemical Feedstock	—	—	—	—	—	—	—	—
Other Products	4.0	4.2	4.4	4.6	5.1	6.4	7.9	9.3
Total All Products	**52.6**	**53.2**	**53.9**	**54.1**	**57.8**	**65.9**	**76.1**	**85.3**
Without Conservation								
Total All Products	**52.6**	**54.0**	**55.2**	**56.4**	**62.2**	**73.6**	**87.3**	**100.6**

Table 9
NEB Forecast of
Petroleum Product Demand
Manitoba
With and Without Conservation
Mb/d

With Conservation	1974	1975	1976	1977	1980	1985	1990	1994
Motor Gasoline	26.2	26.8	27.1	27.8	29.2	32.6	36.7	41.4
Light Fuel Oil, Kerosene and Stove Oil	7.7	7.5	7.5	7.3	7.1	6.9	6.8	6.5
Diesel Fuel Oil	11.9	12.2	12.7	13.1	14.7	17.4	20.4	23.0
Heavy Fuel Oil	3.4	3.4	3.3	3.3	3.2	3.1	3.0	2.9
Petrochemical Feedstock	–	–	–	–	–	–	–	–
Other Products	6.7	6.9	7.2	7.3	8.0	9.5	11.1	12.6
Total All Products	**55.9**	**56.8**	**57.8**	**58.8**	**62.2**	**69.5**	**78.0**	**86.4**
Without Conservation								
Total All Products	**55.9**	**57.5**	**59.3**	**61.0**	**66.8**	**77.7**	**90.5**	**102.3**

Table 10
NEB Forecast of
Petroleum Product Demand
Saskatchewan
With and Without Conservation
Mb/d

With Conservation	**1974**	**1975**	**1976**	**1977**	**1980**	**1985**	**1990**	**1994**
Motor Gasoline	30.9	31.2	31.3	31.5	32.3	34.4	37.4	40.1
Light Fuel Oil, Kerosene and Stove Oil	7.4	7.3	7.2	7.0	6.8	6.7	6.5	6.3
Diesel Fuel Oil	13.5	13.8	14.1	14.4	15.4	17.0	18.8	20.7
Heavy Fuel Oil	.7	.7	.7	.7	.7	.7	.7	.6
Petrochemical Feedstock	—	—	—	—	—	—	—	—
Other Products	6.0	6.2	6.4	6.6	7.3	8.6	10.2	11.6
Total All Products	**58.5**	**59.2**	**59.7**	**60.2**	**62.5**	**67.4**	**73.6**	**79.3**
Without Conservation								
Total All Products	**58.5**	**60.0**	**61.3**	**62.8**	**67.1**	**75.2**	**84.4**	**92.7**

Table 11
NEB Forecast of
Petroleum Product Demand
Alberta
With and Without Conservation
Mb/d

With Conservation	**1974**	**1975**	**1976**	**1977**	**1980**	**1985**	**1990**	**1994**
Motor Gasoline	58.4	59.9	61.0	62.1	66.8	76.5	89.4	101.7
Light Fuel Oil, Kerosene and Stove Oil	3.6	3.5	3.5	3.4	3.3	3.2	3.2	3.1
Diesel Fuel Oil	23.3	24.1	25.4	26.6	30.6	37.9	46.8	55.7
Heavy Fuel Oil	1.9	1.9	1.9	1.9	1.8	1.7	1.7	1.7
Petrochemical Feedstock	0.1	0.1	0.1	0.1	25.1	60.6	60.6	60.6
Other Products	30.6	31.8	33.0	34.0	37.5	44.8	53.5	61.4
Total All Products	**117.9**	**121.3**	**124.9**	**128.1**	**165.1**	**224.7**	**255.2**	**284.2**
Without Conservation								
Total All Products	**117.9**	**122.6**	**127.8**	**133.1**	**174.3**	**242.1**	**281.6**	**319.4**

Table 12
NEB Forecast of
Petroleum Product Demand
British Columbia
With and Without Conservation
Mb/d

With Conservation	1974	1975	1976	1977	1980	1985	1990	1994
Motor Gasoline	61.0	62.5	63.6	65.0	69.7	80.0	93.1	105.9
Light Fuel Oil, Kerosene and Stove Oil	21.5	21.4	21.4	21.3	21.3	22.2	23.2	23.5
Diesel Fuel Oil	30.9	32.1	33.9	35.5	41.1	51.3	63.9	76.7
Heavy Fuel Oil	27.4	26.3	26.1	25.8	27.7	32.7	40.0	44.3
Petrochemical Feedstock	0.9	0.9	0.9	0.9	0.9	1.4	1.9	2.4
Other Products	18.0	18.8	19.7	20.4	23.1	28.6	35.4	43.8
Total All Products	**159.7**	**162.0**	**165.6**	**168.9**	**183.8**	**216.2**	**257.5**	**296.6**
Without Conservation								
Total All Products	**159.7**	**164.2**	**169.8**	**175.4**	**196.8**	**239.6**	**292.4**	**345.7**

Table 13
NEB Forecast of
Petroleum Product Demand
Yukon and the Northwest Territories
With and Without Conservation
Mb/d

With Conservation	1974	1975	1976	1977	1980	1985	1990	1994
Motor Gasoline	1.5	1.6	1.6	1.8	2.0	2.4	2.9	3.2
Light Fuel Oil, Kerosene and Stove Oil	3.1	3.1	3.2	3.2	3.5	4.1	4.8	5.4
Diesel Fuel Oil	3.9	4.2	4.4	4.7	5.7	7.5	10.0	12.5
Heavy Fuel Oil	.4	.4	.4	.4	.4	.4	.4	.4
Petrochemical Feedstock	–	–	–	–	–	–	–	–
Other Products	1.9	2.0	2.1	2.3	2.6	3.5	4.6	5.8
Total All Products	**10.8**	**11.3**	**11.7**	**12.4**	**14.2**	**17.9**	**22.7**	**27.3**
Without Conservation								
Total All Products	**10.8**	**11.4**	**12.0**	**12.8**	**15.0**	**19.4**	**25.0**	**30.8**

Table 14
NEB Estimates of
The Effect of Conservation on the Demand for Energy

A. Transportation Sector

Action	Motivating Force	Saving by 1994
— Smaller vehicles and smaller engines	Price and government programs	4% – 5%
— Reduced speed limits	Government legislation	3% – 4%
— Increased use of mass transit and railroads, electrification of railway lines, increased load factors	Price and government programs	3% – 4%
— Increased vehicle motive efficiency (power train, aerodynamic drag)	Price	4% – 5%
— Introduction of automobile diesel engines, stratified charge engines and electric vehicles	Price	1% – 2%
— Improved vehicle maintenance and improved driving habits	Price	1% – 2%
Total		Approximately 17%
Range of Submissions		15% – 30%

Table 14
NEB Estimates of
The Effect of Conservation on the Demand for Energy

B. Residential/Commercial Sector

Action	Motivating Force	Saving by 1994
— Lower thermostat settings in the winter by approximately 1° – 2° C	Price for residential , price and government programs for commercial	3% – 4%
— Less air conditioning in commercial buildings in the summer	Price and government programs	
— Improved residential insulation (new houses insulated to electrical standards)	Price and government programs	3% – 4%
— Improved sealing and additional ceiling insulation in existing residential units	Price	3% – 4%
— Improved furnace efficiency	Price and government programs	1% – 2%
— Improved technology and architectural changes relating to the energy intensiveness of commercial buildings	Price and government programs	4% – 5%
Total		Approximately 15%
Range of Submissions		10% – 22%

Table 14
NEB Estimates of
The Effect of Conservation on the Demand for Energy

C. Industrial Sector

Action	Motivating Force	Saving by 1994
— Technological advances leading to more-efficient processes and more-efficient plants	Price	6% – 8%
— Replacing and upgrading old and inefficient equipment	Price	3% – 4%
— More regular and complete maintainance of existing equipment	Price	2% – 4%
Total		Approximately 15%
Range of Submissions		8% – 36%

Table 15
1974 REQUIREMENT FOR CRUDE AND EQUIVALENT
Mb/d

EAST OF THE OTTAWA VALLEY LINE	Gulf	Imperial	Shell	Texaco	NEB
Net Product Sales	755	739	771	752	749
Deduct Product Imports	(47)	(47)	(52)	(60)	(46)
Add Product Exports	96	97	92	103	110
Add Product Transfers to West of the Ottawa Valley Line	24	26	30	35	28
Add Own Use/Loss and other Adjustments	55	54	48	70	47
Requirement for Crude and Equivalent	883	869	889	900	888
WEST OF THE OTTAWA VALLEY LINE					
Net Product Sales	860	861	870	858	850
Deduct Product Imports	(22)	(24)	(23)	(30)	(24)
Add Product Exports	16	20	20	24	29
Deduct Product Transfers from East of the Ottawa Valley Line	(24)	(26)	(30)	(35)	(28)
Add Own Use/Loss and Other Adjustments	35	56	29	48	38
Requirement for Crude and Equivalent	865	887	866	865	865
CANADA					
Net Product Sales	1615	1600	1641	1610	1599
Deduct Product Imports	(69)	(71)	(75)	(90)	(70)
Add Product Exports	112	117	112	127	139
Add Own Use/Loss and Other Adjustments	90	110	77	118	85
Requirement for Crude and Equivalent	1748	1756	1755	1765	1753

Table 15
1975 REQUIREMENT FOR CRUDE AND EQUIVALENT
Mb/d

	Gulf	Imperial Case A	Shell Base Case	Texaco	NEB Base Case	NEB Conservation Case
EAST OF THE OTTAWA VALLEY LINE						
Net Product Sales	791	753	789	787	768	758
Deduct Product Imports	(32)	(14)	(44)	(59)	(40)	(40)
Add Product Exports	115	64	87	165	70	70
Add Product Transfers to West of the Ottawa Valley Line	42	32	20	44	40	40
Add Own Use/Loss and Other Adjustments	53	56	56	59	55	55
Requirement for Crude and Equivalent	969	891	908	996	893	883
WEST OF THE OTTAWA VALLEY LINE						
Net Product Sales	899	889	895	896	896	885
Deduct Product Imports	(13)	(11)	(27)	(28)	(20)	(20)
Add Product Exports	15	0	12	40	30	30
Deduct Product Transfers from East of the Ottawa Valley Line	(42)	(32)	(20)	(44)	(40)	(40)
Add Own Use/Loss and Other Adjustments	55	58	44	50	47	46
Requirement for Crude and Equivalent	914	904	904	914	913	901
CANADA						
Net Product Sales	1690	1642	1684	1683	1664	1643
Deduct Product Imports	(45)	(25)	(71)	(87)	(60)	(60)
Add Product Exports	130	64	99	205	100	100
Add Own Use/Loss and Other Adjustments	108	114	100	109	102	101
Requirement for Crude and Equivalent	1883	1795	1812	1910	1806	1784

Table 15
1976 REQUIREMENT FOR CRUDE AND EQUIVALENT
Mb/d

	Gulf	Shell Base Case	Texaco	NEB Base Case	NEB Conservation Case
EAST OF THE OTTAWA VALLEY LINE					
Net Product Sales	841	825	823	816	797
Deduct Product Imports	(24)	(48)	(58)	(15)	(15)
Add Product Exports	127	86	239	100	100
Add Product Transfers to West of the Ottawa Valley Line	56	20	44	35	35
Add Own Use/Loss and Other Adjustments	61	58	62	62	61
Requirement for Crude and Equivalent	1061	941	1110	998	978
WEST OF THE OTTAWA VALLEY LINE					
Net Product Sales	946	953	934	924	902
Deduct Product Imports	(8)	(33)	(27)	(5)	(5)
Add Product Exports	14	5	40	30	30
Deduct Product Transfers from East of the Ottawa Valley Line	(56)	(20)	(44)	(35)	(35)
Add Own Use/Loss and Other Adjustments	58	57	53	50	49
Requirement for Crude and Equivalent	954	962	956	964	941
CANADA					
Net Product Sales	1787	1778	1757	1740	1699
Deduct Product Imports	(32)	(81)	(85)	(20)	(20)
Add Product Exports	141	91	279	130	130
Add Own Use/Loss and Other Adjustments	119	115	115	112	110
Requirement for Crude and Equivalent	2015	1903	2066	1962	1919

Table 15
1977 REQUIREMENT FOR CRUDE AND EQUIVALENT
Mb/d

EAST OF THE OTTAWA VALLEY LINE	Gulf	Shell Base Case	Texaco	NEB Base Case	NEB Conservation Case
Net Product Sales	886	863	862	858	827
Deduct Product Imports	(9)	(49)	(57)	(15)	(15)
Add Product Exports	128	86	248	110	110
Add Product Transfers to West of the Ottawa Valley Line	54	20	42	30	30
Add Own Use/Loss and Other Adjustments	68	60	65	65	63
Requirement for Crude and Equivalent	1127	980	1160	1048	1015
WEST OF THE OTTAWA VALLEY LINE					
Net Product Sales	1000	1021	977	1003	968
Deduct Product Imports	(8)	(19)	(26)	(5)	(5)
Add Product Exports	14	12	100	30	30
Deduct Product Transfers from East of the Ottawa Valley Line	(54)	(20)	(42)	(30)	(30)
Add Own Use/Loss and Other Adjustments	60	62	56	56	54
Requirement for Crude and Equivalent	1012	1056	1065	1054	1017
CANADA					
Net Product Sales	1886	1884	1839	1861	1795
Deduct Product Imports	(17)	(68)	(83)	(20)	(20)
Add Product Exports	142	98	348	140	140
Add Own Use/Loss and Other Adjustment	128	122	121	121	117
Requirement for Crude and Equivalent	2139	2036	2225	2102	2032

Table 15
1980 REQUIREMENT FOR CRUDE AND EQUIVALENT
Mb/d

	Gulf	Imperial Case A	Shell Base Case	Shell Conservation Case	Texaco	NEB Base Case	NEB Conservation Case
EAST OF THE OTTAWA VALLEY LINE							
Net Product Sales	993	875	972	864	975	948	890
Deduct Product Imports	0	(19)	(45)	(40)	(55)	(40)	(40)
Add Product Exports	135	122	83	883	340	130	130
Add Product Transfers to West of the Ottawa Valley Line	23	20	20	20	36	30	30
Add Own Use/Loss and Other Adjustments	72	59	68	60	74	71	67
Requirement for Crude and Equivalent	1223	1057	1098	987	1370	1139	1077
WEST OF THE OTTAWA VALLEY LINE							
Net Product Sales	1191	1072	1166	1017	1106	1168	1099
Deduct Product Imports	(11)	(2)	(12)	(12)	(25)	0	0
Add Product Exports	9	3	19	67	110	30	30
Deduct Product Transfers from East of the Ottawa Valley Line	(23)	(20)	(20)	(20)	(36)	(30)	(30)
Add Own Use/Loss and Other Adjustments	71	64	72	61	65	68	63
Requirement for Crude and Equivalent	1237	1117	1225	1113	1220	1236	1162
CANADA							
Net Product Sales	2184	1947	2138	1881	2081	2116	1989
Deduct Product Imports	(11)	(21)	(57)	(52)	(80)	(40)	(40)
Add Product Exports	144	125	102	150	450	160	160
Add Own Use/Loss and Other Adjustments	143	123	140	121	139	139	130
Requirement for Crude and Equivalent	2460	2174	2323	2100	2590	2375	2239

Table 15
1985 REQUIREMENT FOR CRUDE AND EQUIVALENT
Mb/d

	Gulf	Imperial	Shell		Texaco	NEB	
		Case A	Base Case	Conservation Case		Base Case	Conservation Case
EAST OF THE OTTAWA VALLEY LINE							
Net Product Sales	1194	1012	1132	940	1189	1116	1010
Deduct Product Imports	0	(15)	(45)	(40)	(52)	(40)	(40)
Add Product Exports	130	139	68	83	325	140	140
Add Product Transfers to West of the Ottawa Valley Line	20	(1)	0	0	26	30	30
Add Own Use/Loss and Other Adjustments	81	68	80	66	89	82	75
Requirement for Crude and Equivalent	1425	1203	1235	1049	1577	1328	1215
WEST OF THE OTTAWA VALLEY LINE							
Net Product Sales	1398	1282	1285	1064	1350	1402	1279
Deduct Product Imports	(11)	(2)	(12)	0	(23)	0	0
Add Product Exports	5	3	0	68	20	30	30
Deduct Product Transfers from East of the Ottawa Valley Line	(20)	1	0	0	(26)	(30)	(30)
Add Own Use/Loss and Other Adjustments	85	71	80	65	80	82	74
Requirement for Crude and Equivalent	1457	1355	1353	1197	1401	1484	1353
CANADA							
Net Product Sales	2592	2294	2417	2004	2539	2518	2289
Deduct Product Imports	(11)	(17)	(57)	(40)	(75)	(40)	(40)
Add Product Exports	135	142	68	151	345	170	170
Add Own Use/Loss and Other Adjustments	166	139	160	131	169	164	149
Requirement for Crude and Equivalent	2882	2558	2588	2246	2978	2812	2568

Table 15
1990 REQUIREMENT FOR CRUDE AND EQUIVALENT
Mb/d

	Gulf	Imperial		Shell		Texaco	NEB	
		Case A	Case B	Base Case	Conservation Case		Base Case	Conservation Case
EAST OF THE OTTAWA VALLEY LINE								
Net Product Sales	1418	1140	909	1347	1041	1433	1323	1176
Deduct Product Imports	0	(17)	(17)	(45)	(40)	(50)	(40)	(40)
Add Product Exports	112	0	131	27	80	300	60	60
Add Product Transfers to West of the Ottawa Valley Line	12	37	10	0	0	16	15	15
Add Own Use/Loss and Other Adjustments	90	70	64	95	74	104	89	80
Requirement for Crude and Equivalent	1632	1230	1097	1424	1155	1803	1447	1291
WEST OF THE OTTAWA VALLEY LINE								
Net Product Sales	1600	1486	1187	1463	1175	1627	1655	1473
Deduct Product Imports	(10)	(2)	(2)	(12)	0	(20)	0	0
Add Product Exports	5	23	23	0	64	15	30	30
Deduct Product Transfers from East of the Ottawa Valley Line	(12)	(37)	(10)	0	0	(16)	(15)	(15)
Add Own Use/Loss and Other Adjustments	98	82	64	95	72	95	101	89
Requirement for Crude and Equivalent	1681	1552	1262	1546	1311	1701	1771	1577
CANADA								
Net Product Sales	3018	2626	2096	2810	2216	3060	2978	2649
Deduct Product Imports	(10)	(19)	(19)	(57)	(40)	(70)	(40)	(40)
Add Product Exports	117	23	154	27	144	315	90	90
Add Own Use/Loss and Other Adjustments	188	152	128	190	146	199	190	169
Requirement for Crude and Equivalent	3313	2782	2359	2970	2466	3504	3218	2868

Table 15

1994 REQUIREMENT FOR CRUDE AND EQUIVALENT

Mb/d

EAST OF THE OTTAWA VALLEY LINE	Gulf	Imperial		Shell		Texaco	NEB	
		Case A	Case B	Base Case	Conservation Case		Base Case	Conservation Case
Net Product Sales	1606	1282	983	1515	1114	1641	1530	1329
Deduct Product Imports	0	(17)	(17)	(46)	(33)	(48)	(40)	(40)
Add Product Exports	100	0	57	0	80	300	60	60
Add Product Transfers to West of the Ottawa Valley Line	8	20	10	0	0	6	15	15
Add Own Use/Loss and Other Adjustments	96	79	64	110	79	119	102	90
Requirement for Crude and Equivalent	1810	1364	1097	1579	1240	2018	1667	1454
WEST OF THE OTTAWA VALLEY LINE								
Net Product Sales	1769	1673	1284	1632	1261	1870	1881	1636
Deduct Import Sales	(10)	(2)	(2)	0	(5)	(18)	0	0
Add Export Sales	5	15	15	0	50	10	30	30
Deduct Product Transfers from East of the Ottawa Valley Line	(8)	(20)	(10)	0	0	(6)	(15)	(15)
Add Own Use/Loss and Other Adjustments	108	102	79	103	78	110	117	101
Requirement for Crude and Equivalent	1864	1768	1366	1735	1384	1966	2013	1752
CANADA								
Net Product Sales	3375	2955	2267	3147	2375	3511	3411	2965
Deduct Product Imports	(10)	(19)	(19)	(46)	(38)	(66)	(40)	(40)
Add Product Exports	105	15	72	0	130	310	90	90
Add Own Use/Loss and Other Adjustments	204	181	143	213	157	229	219	191
Requirement for Crude and Equivalent	3674	3132	2463	3314	2624	3984	3680	3206

Table 16
NEB FORECAST OF FEEDSTOCK REQUIREMENT FOR INDIGENOUS CRUDE OIL AND EQUIVALENT
Mb/d

	Total Canadian Demand	
	Excluding effect of measures designed to reduce consumption	Including effect of measures designed to reduce consumption
1974	942	942
1975	923	911
1976	1064	1041
1977	1304	1267
1980	1486	1412
1985	1734	1603
1990	2021	1827
1994	2263	2002

Note: Included in demand are the following volumes of crude shipped to refiners east of the Ottawa Valley Line

1974 — 77 Mb/d shipped by marine

1975 — 10 Mb/d shipped by marine

1976 — 100 Mb/d shipped by pipeline, including line fill

1977 to 1994 — 250 Mb/d shipped by pipeline

CANADIAN OIL SUPPLY & REQUIREMENTS

NATIONAL ENERGY BOARD FEB 1977

Contents

List of Appendices

List of Figures

List of Tables

Counsel and Witnesses

A public hearing in the matter of producibility of Canadian oil, the domestic demand for oil and for indigenous feedstocks, the effects of conservation on Canadian consumption, the surplus of Canadian oil, the need to change the licensing of crude oil exports, and related matters, held pursuant to Part 1 of the National Energy Board Act.

File: 1722-9-2

Heard at Calgary, Alberta on 19, 20 and 21 October 1976
Ottawa, Ontario on 26, 27 and 28 October 1976

Before

M.A. Crowe (Chairman NEB) — as Presiding Member duly appointed by the Board for that purpose in accordance with Section 14 of the National Energy Board Act.

Appearances:

Calgary	D. Hart D. Havlena R. Towler	Petrochemicals Alberta Project (Petrochemicals Alberta)
	G. Palmer H.S. Simpson	Canadian Petroleum Association (C.P.A.)
	M. Abougoush W. Fisher	D & S Petroleum Consultants (1974) Ltd. (D & S)
	D.D. Smith J.D. Griffith V. Mackenzie V. Peters	Amoco Canada Petroleum Company Ltd. (Amoco)
	W.J. Hope-Ross A.F. Burchnall	BP Exploration Canada Limited (B.P.)
	R. Pashelka J. Scott	Chevron Standard Limited (Chevron)
	S. Trueman C. R. Hetherington	Panarctic Oils Ltd. (Panarctic)
	W.F. Blaine L.J. Flaman W.M. Hougland	Koch Oil Co. Ltd. (Koch)

Calgary	A.G. Morison M.L. Johns	Home Oil Company Limited (Home Oil)
	D. Hart I. Martin G.R. Crandall	PanCanadian Petroleum Limited (PanCanadian)
	L.S. Heald R.E. McLennan	Canadian Hidrogas Resources Ltd. (Canadian Hidrogas)
	M.A. Putnam D.G. Gunderson D.M. Wylie J. Paweluk	Pacific Petroleums Ltd. (Pacific)
	D.D. Pope R. Aberg D.F. Hughes K.R. MacGregor Dr. C.R. Mattinson B.F. Stanley L.J. Schofield	Shell Canada Limited (Shell)
	A.L. McLarty V. Millard F. Mink H. Antonio	Alberta Energy Resources Conservation Board (AERCB or Alberta Board)
	R.A. Robertson	The City of Lloydminster (Lloydminster)
	D. Bogdasavich E.G. Dennison P.L. Black	Government of Saskatchewan (Saskatchewan)
	W.G. Loewen R.R. Andrews	Dome Petroleum Limited (Dome)
	J.L. Gaffney K.W. Lloyd J. McKibbon R.W. Hoover J.C. Gateman	Hudson's Bay Oil and Gas Company Limited (HBOG)
	A.J. Hepworth	British Columbia Energy Commission (B.C. Energy Commission)
Ottawa	R.P. Smith I. Rowe	Ontario Ministry of Energy (Ontario)

Ottawa	J. Stein J.M. Taylor G.C. Watkins W.G. Trimble	Independent Petroleum Association of Canada (IPAC)
	G. Dube H.E. Joudrie R.R. McDaniel G.R. Crandall F.E. Staratt	Ashland Oil Canada Limited (Ashland)
	B.F. Sim J.R. Dundas B.P. Dorin	Canadian Reserve Oil and Gas Ltd. (Canadian Reserve)
	T.J. Hitchcock P.D. White	General Crude Oil Company Northern (General Crude)
	H. Ward G.A. Connell R.V. Lang J.E. West H.C. Simmons T.R. Mahashi	Gulf Oil Canada Limited (Gulf)
	M.A. Putnam R.Y. Pogontcheff R.D. Orr J.S. Beasley	Husky Oil Operations Ltd. (Husky)
	M.G. Dunko D.D. Lougheed D.K. Reynolds W.A. Bain F.J. Bagley	Imperial Oil Limited (Imperial)
	D.W. MacFarlane R.J. Nicholl J.W. Harper H.G. Groeneveld	Mobil Oil Canada Ltd. (Mobil)
	M.A. Putnam L. Pasychny R.G. Farquharson	Murphy Oil Company Ltd. (Murphy)
	G.F. Finlayson S.K. Lamb J.D. Forbes	Petrosar Limited (Petrosar)

Ottawa	F.J. Newbould B.T. Abbott K.V. Liddon	Sun Oil Company of Canada Ltd. (Sun)
	P.R. Carpenter W. Beaudry J.G. Pashniak	Texaco Canada Limited (Texaco)
	A.D. Gardner G.F. McIntyre W.S. Hunter	Ontario Hydro

Glossary of Terms

ABBREVIATIONS

API American Petroleum Institute.

bbls. barrels; 1 barrel is equal to 34.9723 Imperial gallons.

Btu British thermal unit; the amount of heat required to raise the temperature of one pound of water 1 degree Fahrenheit.

EOV East of the Ottawa Valley (Line).

FEA Federal Energy Administration (United States).

GCOS Great Canadian Oil Sands Ltd.

GNP Gross National Product.

GPP Gross Provincial Product.

LPG Liquefied Petroleum Gases.

Mb/d Thousand barrels per day.

Mcf Thousand cubic feet.

MMstb Million stock tank barrels.

NGL Natural Gas Liquids.

Quad Equal to 1 quadrillion Btu's. A quadrillion is equal to one million billion, i.e., 10^{15}.

WOV West of the Ottawa Valley (Line).

DEFINITIONS

°API — Degree(s) API. A relative measure of the specific gravity of crude oils. Crude oils with a higher value of °API have a lower specific gravity.

Bitumen — A naturally occurring viscous mixture comprised mainly of hydrocarbons heavier than pentane which may contain sulphur compounds and that in its natural state is not recoverable at a commercial rate through a well.

Carbon Dioxide ("CO_2") Miscible Flooding — A tertiary recovery process in which carbon dioxide is injected into the reservoir under conditions at which the injected material mixes with the reservoir fluid.

Chemical Flooding — A tertiary recovery process in which chemicals are added to water injected into a petroleum reservoir. Three of the common groups of chemicals which may be added are surfactants, polymers, and alkaline chemicals.

Condensate — As used herein, synonymous with pentanes plus.

Conventional Areas — Those areas of Canada which have a long history of oil production. The term "conventional" also refers to those reservoirs which in their natural state will flow oil to a wellbore in commercial quantities.

Elasticity — In relation to demand, a measure of the responsiveness of demand for a product to a change in values of the variables affecting demand.

Enhanced Recovery — See "Recovery".

Established Reserves — Those reserves, both naturally occurring and synthetic, which on the basis of identified economic considerations and within a specified time frame, are considered to be recoverable with a high degree of certainty from known reservoirs, through the application of currently accepted recovery techniques.

Feedstock — Raw material supplied to a refinery.

Frontier Reserves — Reserves of crude oil in the offshore areas, the Arctic region, and the Mackenzie Delta-Beaufort Sea area.

Heavy Crude Oil — A term loosely applied to crude oils with a low API gravity. For a more detailed explanation of the National Energy Board's classification of heavy crude oil see Table VI-1.

Improved Recovery — See "Recovery".

In Situ Recovery — With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.

International Price of Crude Oil — A generalization for the "going price" of crude oil in the world markets.

Middle Distillates — The range of refined petroleum products which includes kerosene, stove oil, diesel fuel, and light fuel oil.

Northern Tier Refineries — A general term which refers to refineries located in states bordering on Canada which have in the past been dependent on Canadian crude. This term is often used interchangeably with the term "Priority 1 Refineries".

Oil Sands — Deposits of sand and other rock aggregate which contain bitumens. See also "Bitumen".

Original Oil-in-Place — See "Recovery".

Pentanes Plus — A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally, a by-product obtained from the production and processing of natural gas.

Potential Producibility — The estimated average annual ability to produce, unrestricted by demand but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing and pipeline capacity, that could be achieved on ninety day's notice.

Priority 1 Refineries — A classification assigned to a group of 11 refineries and utilities in Montana, Minnesota, Michigan, and Wisconsin by the Federal Energy Administration. These refiners are largely dependent on Canadian exports for their crude oil supply.

Recovery

- *Original Oil-in-Place* — The total calculated volume of crude oil within a discovered petroleum reservoir before production is obtained, of which only a portion is recoverable.
- *Primary Recovery* — Crude oil recovery from a petroleum reservoir resulting from the natural energy of the reservoir to move the crude oil toward producing wells.
- *Secondary Recovery* — The additional crude oil recovery from a petroleum reservoir obtained by supplying energy to supplement or replace the energy of primary recovery. Generally, the term refers to already technically and economically proven methods such as waterflooding, gas injection, and steam injection.
- *Tertiary Recovery* — The additional crude oil recovery from petroleum reservoirs through the application of third generation methods. These methods are the newer, less technically proved techniques such as the thermal processes, carbon dioxide miscible flooding, hydrocarbon miscible flooding, and chemical flooding.
- *Improved or Enhanced Recovery* — General terms used to include all crude oil recovery from a petroleum reservoir which is incremental to primary recovery.

Requirements for Indigenous Feedstocks — Requirements WOV plus 250 Mb/d for the area EOV.

Reserve Appreciation — Growth in the reserves credited to a pool or area due to additional delineation of reservoirs through development drilling or the application of improved recovery methods.

Scenario — A set of conditions or relationships. As used in this report "price scenarios" are used to examine the effect that various crude oil prices could have on supply and demand. Three trends in international prices of crude oil are considered in this report and for each of the cases it is assumed that Canadian crude oil prices will approach international levels by 1980. In addition, each case is characterized by one of the following underlying assumptions:

- *Low Price Case* — world oil price assumed to remain at current levels,
- *Medium Price Case* — world oil price is assumed to increase at international inflation rates; that is, it remains constant in real terms,
- *High Price Case* — real world oil price is assumed to grow at an annual rate of 5%.

Syncrude Canada ("Syncrude") — A consortium formed to develop a mining plant and bitumen upgrading facility in the Athabasca oil sands. At present this group consists of Imperial Oil Limited, Gulf Oil Canada Limited, Canada-Cities Service Ltd., Petro-Canada and the Governments of Alberta and Ontario.

Synthetic Crude Oil — Crude oil produced through treatment of bitumen in upgrading facilities designed to decrease its viscosity and sulphur content. See also "Bitumen".

Tertiary Recovery — See "Recovery".

Thermal Processes — Tertiary recovery processes in which heat is added to the reservoir. Two principal thermal processes are steam flooding and in situ combustion. In steam flooding, steam is injected into the reservoir. In situ combustion involves ignition of oil in the reservoir and burning a portion of the oil-in-place to generate heat.

Wellhead — Specifically, the equipment placed on top of a well at the surface to maintain control of the well. More generally, it is used to specify a delivery point in the crude oil production system, e.g., the wellhead price.

World Price — See "International Price".

Summary and Conclusions

A comprehensive hearing on the subject of the exportation of oil was held by the National Energy Board ("NEB" or "the Board") in April and May 1974 and the findings were released in a report in October of that year. As a result of that hearing the Board adopted a protection procedure designed to limit exports when 10 years of future Canadian requirements for indigenous crude oil and equivalent feedstocks could not be assured. A further conclusion of the report was that public hearings should be held periodically to receive evidence with respect to the potential producibility of oil in Canada, the requirements for indigenous feedstocks and the effects of conservation on Canadian consumption and exportable surplus.

The first of these periodic hearings was held in April 1975 and the findings were released in a report in September of that year. The result of that hearing was a further reduction in allowable export volumes in the light of the growing possibility of supply difficulties facing Canadian users of indigenous crude oil and equivalent.

The second of these periodic hearings was held in October 1976 in Calgary and Ottawa under Part I of the National Energy Board Act. Thirty-seven companies and government agencies filed submissions in response to the Notice of Hearing (Appendix A) issued on 19 February 1976 and thirty-three of these submittors appeared, to give viva voce evidence at the hearing.

This is a report of the evidence presented to the Board and its findings on the subject matters of the hearing. The report differs from the two previous reports in several respects. The forecasts of requirements for indigenous feedstocks are developed within a total primary energy demand framework for those sectors of energy demand where oil products are in market competition with other sources of energy such as natural gas, hydro, nuclear and coal. Alternative supply and demand scenarios are presented to emphasize the uncertainty inherent in forecasting the future. Finally, the supply of and requirements for heavy crude oil are treated separately from those of light crude oil and equivalent.

SUPPLY OF CRUDE OIL AND EQUIVALENT

The forecast supply of crude oil and equivalent derives from five sources; established reserves in conventional areas, additions to established reserves in conventional areas, pentanes plus reserves, oil sands deposits, and frontier reserves.

The views of submittors regarding established reserves in conventional areas were mainly embodied in completed forecasts for individual pools showing producibility and reserves estimates in the form requested by the Board in its Outline for Submissions (Appendix B). The Board requested these data from the major operators of some 200 individual pools and pool groupings. Analysis of the reserves estimates and producibility forecasts reveals little difference from last year's submissions.

In addition to the detailed pool forecasts, summary forecasts were received from several submittors. These forecasts are compared in Figure II-1.

A number of submissions dealt in specific terms with the potential producibility of heavy crude oil. Comparison of these forecasts is difficult since submittors were not consistent in their definitions of heavy crude oil. The Board has adjusted these potential producibility forecasts to include those pools classified by the Board as heavy crude oil pools, and the resulting forecasts are shown in Figure II-2. The Board's definition of heavy crude oil is discussed in Chapter VI (Table VI-1).

The Board has taken into account all reserves evidence received at the hearing in making its own determinations of established reserves. These estimates are shown in Appendix C on a pool-by-pool basis. During the year, 1 January 1975 to 1 January 1976, remaining reserves of conventional crude oil showed a net decrease of 403.6 million barrels from 6877.9 million barrels to 6474.3 million barrels.

After considering all evidence received in the submissions and in verbal testimony, together with supplementary information supplied after the hearing, the Board has developed the 20 year pool-

by-pool potential producibility forecasts shown in Appendix D. This year, the table shows light crude oil and heavy crude oil separately. The current forecast of the aggregate potential producibility from established reserves shown in Figure II-4 differs little from the forecast presented in the Board's September 1975 report.

The forecasts of potential producibility from additions to established reserves in conventional areas filed at the hearing are summarized graphically in Figures II-5 and II-6.

At the Board's 1975 hearing there appeared to be a consensus that reserves additions would accrue largely from improved recovery methods as opposed to new discoveries. That remained the consensus at the current hearing. Although appreciation of discovered pools and waterflooding stili have significant potential, most of the improved recovery reserves additions are expected to result from the application of tertiary recovery methods.

The Board has examined the evidence regarding improved recovery potential, and in conjunction with its own studies has evaluated each established oil reservoir in Canada for improved recovery potential. The results are summarized in Table II-1. Also shown are estimates of new discovery potential. The aggregate potential for reserves additions for the expected case is estimated to be 3.17 billion barrels of which 1.10 billion barrels are expected to accrue from new discoveries and 2.07 billion barrels from improved recovery methods in discovered reservoirs. Of the 2.07 billion barrels, 1.54 billion barrels are credited to tertiary recovery methods: chemical flooding, miscible flooding and thermal techniques. The remaining 0.53 billion barrels result from infill drilling and waterflooding.

Approximately one-half of the aggregate potential for reserves additions is attributed to further exploitation of heavy crude oil reservoirs. The Board believes that these developments will occur provided that wellhead prices move towards international levels, and that markets are available for the heavy crude oil production.

The Board's forecasts of potential producibility from additions to established reserves are shown in Figures II-7 and II-8. The forecasts are slightly higher than those in the September 1975 report, because the Board is more optimistic about the prospects for heavy crude oil development.

The views of submittors regarding pentanes plus reserves were principally detailed in forecasts for individual natural gas processing plants in the form requested by the Board in its Outline for Submissions. The forecasts of pentanes plus production submitted to the Board along with the Board's forecast are shown in Figure II-9. The Board's current forecast is lower than the forecast published in its September 1975 report. While a portion of this reduction reflects poorer than expected performance in some pools, the larger part is a result of the more detailed study related to this year's forecast.

Detailed oil sands potential producibility forecasts were received from five submittors. The forecasts varied widely, as shown in Figure II-10, from Shell's case which assumed no projects after Syncrude to Imperial's potential development case which showed producibility of nearly 800 Mb/d by 1995. Submittors identified three problem areas that must be resolved before additional plants can proceed: government assistance with financing, world oil prices for synthetic crude oil production, and substantially reduced (or no) government taxes and royalties.

The Board is convinced that the oil sands development rate shown in its September 1975 report will not be realized and that a significant downward adjustment is called for in view of the current expectations. The Board is generally in agreement with the concerns voiced by the submittors at the hearing. On the basis of the evidence presented at the hearing and its own studies, the Board has constructed the notional development forecast shown in Figure II-11. Although estimation of future oil sands development is less certain than forecasting production from established reserves, it is important to remember that the timing of these projects has no effect on the calculation of the level of crude oil exports, since the predicted domestic shortfall occurs well before any possible start-up date for a third plant.

A summary of the submitted information regarding frontier crude oil supply is shown in Table II-5. In all cases the estimates are considerably lower than those provided to the Board last year by the same companies.

The Board sees no reason to change its previously published finding that oil production from the frontier areas remains too speculative to warrant inclusion in a procedure designed to provide protection for Canadian requirements. It appears highly unlikely that any significant volume of frontier oil production could move to Canadian markets during the ten year period covered by the protection procedure.

A summary of the potential producibility forecasts is provided in Appendix G. Shown are subtotals for light crude oil and equivalent and for heavy crude oil. Figure II-12 graphically illustrates the contribution of each supply source to the availability of total crude oil and equivalent. Reductions in producibility for a particular year during the 10-year protection period from the corresponding estimate in the September 1975 report range from 25 Mb/d or 1.7 percent in 1981 to 132 Mb/d or 11.0 percent in 1985. Reductions during the 10-year period, 1986 – 1995, are larger and result almost entirely from reduced expectations regarding oil sands development.

DEMAND FOR TOTAL ENERGY

In the Outline for Submissions, submittors were requested to consider the demand for refined petroleum products in the context of a total energy outlook and interfuel competition. While the utilization of other energy forms was not considered in detail at this hearing, submittors were requested to provide sufficient information to permit comparative evaluation of the submitted forecasts of refined petroleum product demands.

In making its own determination of Canadian demand for refined petroleum products, the Board has given consideration to the demand for other energy forms. The methodology employed by the Board in forecasting energy demands, the assumptions used in generating the energy demand forecasts, and the resulting forecasts of sectoral energy demands are presented in Chapter III of this report. The major end-use sectors which have been considered in forecasting energy requirements are the residential, commercial, industrial, transportation and petrochemical sectors.

The Board's forecast employs a projection of economic growth based on the CANDIDE econometric model of the Canadian economy. The particular values chosen are similar to one of the economic growth cases used by Energy, Mines and Resources in its published paper "An Energy Strategy for Canada". The forecast of economic activity used assumes real gross national product increasing at an average annual rate of 5.2 percent for the period 1976 to 1980. After 1980, economic growth is forecast to moderate, averaging 3.4 percent over the period 1980 to 1995. Other features characterizing the projection of the economy used by the Board are summarized in Table III-3.

The Board's forecast is based on the assumption that the world price of crude oil will remain constant in real terms at its 1975 level. The domestic price of crude oil is assumed to rise towards the world price of oil, approaching it in 1980. The city-gate price of natural gas in Toronto is assumed to increase to parity with the price of crude oil at the refinery gate on a British Thermal Unit ("Btu") equivalent basis in 1980. After 1980, oil and gas prices are assumed to remain constant in real terms. Electricity prices are assumed to increase in real terms to 1980, remaining constant in real terms thereafter. It should be emphasized that these and other price assumptions are made strictly for forecasting purposes, and that no assumption can be considered to represent government intentions in this area.

The assumptions regarding population, economic growth and energy prices provide the basis for the regional forecasts of total energy demands in the residential, commercial and industrial sectors. It is, however, the market share estimates which determine the division of total energy demand into demands for individual fuels in each regional market.

The market shares incorporated into the Board's forecast were developed on a judgmental basis by considering such factors as relative energy prices, relative capital costs of installation of heating equipment, and historical trends. It should be noted that no supply constraints are assumed on fuels which have been available historically in a given region. Moreover, for the purposes of the forecasts included in this report, it is assumed that no expansion of the gas service area in the Province of Quebec or to Vancouver Island will occur during the forecast period.

The Board forecasts primary energy demand to increase from an actual 1975 level of 8.0 quadrillion Btu's ("quads") to 11.0 quads in 1985 and to 14.3 quads in 1995. This implies an average annual rate of growth of 2.8 percent over the forecast period. Primary oil demand is forecast by the Board to increase more slowly than primary energy demand rising from a 1975 level of 3.5 quads to 4.7 quads in 1985 and to 5.5 quads in 1995 for a growth rate averaging 2.1 percent over the forecast period. The Board's estimate of primary oil demand is within the range of the submitted forecasts.

The Board's forecasts of total energy demand for the residential, commercial and industrial sectors are displayed in Figure III-1. The corresponding figures for the transportation sector are displayed in Figure III-2. For all these sectors, the results are also tabulated in Appendix H along with the corresponding estimate of total oil demand.

To ensure that Canadian consumers receive the benefits from oil conservation programs and from their voluntary reductions in oil consumption resulting from increased prices, the Board's export formula requires that estimates be made of the quantitative impact of conservation. Accordingly, the Board has developed an Export Formula Case which is an estimate of the levels which energy demand would have reached had prices remained at 1972 levels and had conservation programs not been developed. Details regarding the demand for energy and oil products for the Export Formula Case are contained in Chapter III and in Appendix H.

DEMAND FOR REFINED PETROLEUM PRODUCTS

The Board's forecast demand for the major categories of refined petroleum products is shown by sector of consumption for total Canada in Appendix H. In Appendix I, a regional breakdown of this forecast demand is presented by product category.

The Board's projections indicate that over the forecast period from 1976 to 1995, refined petroleum product demand in Canada is expected to increase at an average annual rate of 2.0 percent. Growth is forecast to be more rapid in the initial part of this period, averaging 3.8 percent per year from 1976 to 1980, slowing over the remainder of the forecast period to 1.6 percent per year. Growth in the demand for refined petroleum products is expected to be higher West of the Ottawa Valley, ("WOV") averaging 2.2 percent per year over the forecast period, than East of the Ottawa Valley, ("EOV") where it is forecast at 1.8 percent per year.

The Board's forecast of demand for refined petroleum products is compared to the submittors' most likely forecasts in Figure IV-1.

Motor gasoline and light fuel oil, kerosene and stove oil are expected to decline as a proportion of total product demand, while the remaining products gain. Slowing in the demand for motor gasoline as a result of expected consumer preference for smaller cars, major improvements in fuel economies, and consumer response to gasoline price increases, contributes most significantly to the decline in the rate of increase in total refined petroleum product demand.

REQUIREMENTS FOR FEEDSTOCKS

Future requirements for indigenous feedstocks derive not only from forecast demands for refined petroleum products within Canada, but also from the effects of refiners' and marketers' decisions and plans regarding product imports, regional transfers, refinery utilization, construction of new facilities, closure of existing plants and the future opportunities to sell Canadian products in foreign markets. It is not

surprising, therefore, that forecasts of crude oil and equivalent requirements provided to the Board should exhibit considerable variation. A comparison of these forecasts, which are tabulated in Appendix L along with the Board's shows that the variation becomes more pronounced in the latter years of the forecast period. Appendix M details the submitted forecasts and the Board's forecast for heavy crude oil only. A summary of the Board's forecasts can be found in Appendix N.

Regarding refinery utilization and product exports, the Board holds the view that aggregate runs of indigenous crude oil and equivalent at WOV refineries should be at levels sufficient to meet local demands for light products, with minimal surpluses of motor gasoline or middle distillates. Accordingly, applicants for licences to export product of domestic origin will be required increasingly to show that the volumes sought to be exported have necessarily been manufactured as a consequence of meeting local market needs in an economical manner and with optimum consumption of indigenous feedstocks.

In projecting the post 1980 requirements for WOV feedstocks, the Board has assumed that net product exports will fall to nominal levels by 1990. With respect to product transfers across the Ottawa Valley Line, the Board has assumed that large transfers of heavy fuel oil will not continue after 1979.

For the area EOV, the Board foresees that the refinery capacity presently in place (excluding the shut-down refinery at Come-By-Chance, Newfoundland) will be in excess of local requirements until the post-1985 period. Substantial volumes of heavy fuel oil imports are assumed because the demand for this material in the Atlantic region is forecast to increase its share of the total product demand, and local refineries, faced with uncertain export markets for light products, will not be able to substantially increase their throughput.

On the basis of the Board's forecast of the total requirements for crude oil and equivalent, the average annual rate of growth for the period 1976 – 1995 is estimated to be 2.0 percent. For the Export Formula Case, the average annual rate of growth would be 3.3 percent.

The Board's forecast of requirements for indigenous crude oil and equivalent shown in Appendix N includes along with the WOV requirements, shipments of 250 Mb/d to EOV refineries. A comparison of selected years in the forecast to corresponding values in the September 1975 report shows a slightly higher crude oil and equivalent requirements estimate for 1980, 1423 Mb/d versus 1412 Mb/d, but a substantially lower estimate for 1990, 1535 Mb/d versus 1827 Mb/d.

Forecasts of requirements for indigenous heavy crude oil in Canada were submitted to the Board by a number of companies and agencies. In most cases submittors related WOV requirements for heavy crude oil to forecast demand for asphalt in this area. Forecasts of requirements for indigenous heavy crude oil in the Montreal area were based on experience of heavy crude oil shipments to Montreal, provincial nominations available to August 1976, and judgements as to what general levels of requirements may develop. The possibility that the Sarnia-Montreal pipeline will be reversed in the 1980's was widely cited as a reason that Montreal refiners would not likely install facilities specifically to process indigenous heavy crude oil.

The Board's forecast of WOV requirements for heavy crude oil is based on the forecast of asphalt demand outlined in Chapter IV. The Board's forecast of requirements for heavy crude oil in the Montreal area is based primarily upon testimony presented at the hearing by those Montreal refiners who intend to run it.

LICENSING PROCEDURES

A number of subjects dealt with at the hearing or arising from hearing evidence relate to licensing procedures for crude oil and equivalent exports. The principal items were; need for separate licensing by grade, definition of heavy crude oil, method of determining the heavy crude oil surplus, and exports of refined petroleum products.

All submittors who addressed the subject of separate licensing expressed the view that exports of certain grades of crude oil should be considered separately. In most cases submittors favored special treatment

for heavy crude oil only. However, a few submittors expressed the view that condensate and synthetic crude oil also be considered separately.

It is the Board's view that heavy crude oil should be licensed separately in the future and that determination of export volumes of heavy crude oil should be made independently of export volumes of light crude oil and equivalent. The Board for the most part accepts the reasons for separately licensing heavy crude oil that were presented at the hearing. As regards licensing of condensate and synthetic crude oil it is the Board's view that, at this time, these oils should be treated in the same category as light crude oil, for determination of surplus volumes.

With the above factors in mind, the Board, commencing 1 January 1976, made an interim decision to license heavy crude oil separately and to treat condensate and synthetic crude oil within the light crude oil category. Appendix O is a copy of the Board's press release dated November 23, 1976, which outlines the Board's decision.

With due consideration to producing problems, crude oil quality and marketing characteristics, the Board has decided that the definition of heavy crude oil for the purposes of separate licensing should be the same as that hitherto employed by the Board, namely those grades of crude oil given in Table VI-1. The Board wishes to emphasize that its definition of heavy crude oil is based on current conditions and the Board may change the definition if marketing or supply considerations should, in its opinion, justify such a change.

With regard to the determination of heavy crude oil surplus, the Board has concluded that the public interest is best served by the use of a protection formula the same as is currently used for all crude oils. The use of this formula in setting an exportable surplus for heavy crudes will provide producers with a larger export market than would be the case without separate surplus determination, and at the same time will provide reasonable protection for the present and future requirements for heavy crude oil in Canada.

Submittors were generally in agreement that the licensing of crude oil and refined petroleum products should remain separate. It was felt that the Board should continue to take into account the circumstances involved with each product export application and licenses should only be issued if the particular product to be exported is determined by the Board to be surplus to Canadian needs in regions to which it has access.

The Board agrees with those submittors who indicated that separate volumetric determination for crude oil and equivalent and for refined petroleum product surpluses should continue.

PROTECTION FOR CANADIAN REQUIREMENTS

It is the Board's view, at this time, that Canadian requirements for indigenous feedstocks are adequately protected by application of the existing formula to separate supply-requirements balances for heavy crude oil and for light crude oil and equivalent. Details of the formula are provided in Chapter VII.

For light crude oil and equivalent, allowable export levels are calculated to be 137 Mb/d for 1977. Accordingly, current export levels of some 180 Mb/d will be lowered to 137 Mb/d commencing 1 July 1977. Export levels for subsequent years are currently estimated to be 54 Mb/d in 1978, 20 Mb/d in 1979 and 1 Mb/d in 1980. In mid-1981, it appears likely that those markets in Canada now served by indigenous light crude oil and equivalent will no longer have their full requirements met from domestic production.

With respect to heavy crude oil, the Board's forecasts indicate that indigenous supply will be adequate to meet Canadian requirements for some 15 years. When "t" exceeds 10 years in the Board's export control procedure, the only restriction placed on exports is that Canadian refinery demands must be met first. The remainder of productive capacity is then available for export. Based on current supply and requirements estimates, this situation will exist for the next five years. Export levels, commencing with 1977 are estimated to be 123 Mb/d, 110 Mb/d, 99 Mb/d, 88 Mb/d and 77 Mb/d.

In applying the export formula to the Board's estimates of supply and requirements for light and heavy crude oil, the Board has not adjusted the estimates to account for the effects of upgrading heavy crude oil. Although there are several ways that upgrading could be accounted for in the separate application of the export formula, the net effect of processing heavy crude oil into synthetic light crude oil would be to create additional Canadian requirements for heavy crude oil and additional supply of light crude oil and equivalent. The Board considers the maximization of indigenous heavy crude oil use in Canada to be in the national interest primarily because in the future Canada will have to rely to a much greater degree on oil sands and heavy crude oil reserves.

POSSIBLE RANGE OF SUPPLY AND REQUIREMENTS SCENARIOS

Finally, the Board has examined the possible range of the supply and requirements projections during the next two decades.

In the case of supply, minimum and maximum producibility cases were investigated. The maximum case assumes that each of the four supply determinants, geology, technology, price and government policy was favourable in encouraging supply. The analysis demonstrated that crude oil and equivalent supply is likely to remain within narrow forecast limits over the next decade owing principally to the lead-time required to bring new supplies into production. In the second decade, in 1990 for example, the difference between the minimum and maximum scenarios is 579 Mb/d. Of this total, some 68 percent is from oil sands and about 10 percent is from enhanced recovery.

In the case of requirements, six demand scenarios were calculated combining two forecasts of economic growth and three oil price assumptions. The resulting annual growth rates in requirements for indigenous crude oil and equivalent vary from 1.3 percent for the minimum case to 3.8 percent for the maximum case.

From Figure VIII-4 it can be seen that variation in the estimates of supply and requirements between the minimum and maximum cases does not significantly change the estimated time at which the producibility of indigenous crude oil will no longer be sufficient to meet WOV requirements plus 250 Mb/d for Montreal. This will almost certainly occur between 1981 and 1983.

The most likely case shows that indigenous oil supply will fall short of requirements by approximately 450 Mb/d in 1985, and this shortfall will increase to around 600 Mb/d in the period 1990 to 1995.

Even in the event that the low requirements and high supply forecasts prove to be true, indigenous oil supply is projected to fall short of requirements by approximately 250 Mb/d in 1985, although the shortfall decreases slowly thereafter.

The worst situation considered, the high requirements-low supply case shows that indigenous supply falls short of requirements by about 800 Mb/d in 1985, and by as much as 1800 Mb/d by 1995.

Evidently, imported crude oil will be required in the early 1980's in the markets now served by indigenous crude. Initially, it may be presumed that additional imported crude will be taken into Montreal. Later, it seems likely that WOV refineries will need imported oil. Conceivably, the feedstock requirements of refineries in Ontario and Western Canada could both be met by foreign crude. It appears that Canadians must begin to face up to the problem of supplying imported crude oil to refineries that have for a quarter of a century used only indigenous feedstocks.

Supply of Crude Oil and Equivalent

This section of the report deals with the views received and the Board's views concerning all matters related to Item I.—SUPPLY of the Board's suggested Outline for Submissions (Appendix B). The various oil supply categories are discussed in the following order:

- established reserves in conventional areas,
- additions to established reserves in conventional areas,
- pentanes plus,
- oil sands deposits,
- frontier reserves, and
- summary of potential producibility forecasts.

The protection procedure used by the Board for the calculation of 1975 and 1976 allowable exports of crude oil and equivalent was based on ten year forecasts of potential producibility and of Canadian refinery requirements for indigenous crude oil and equivalent. The 1974 and 1975 reports contained only the Board's best estimate of expected future potential producibility levels; no alternative supply scenarios were published, although upper and lower limits to supply expectations were considered. In this report the Board is publishing alternative development scenarios to improve the understanding of energy options that may arise, and to underline the fact that the future is uncertain. This is not meant to detract from the weight placed on the case which, in the Board's judgement, is the most likely to happen.

Three supply scenarios are calculated in detail and shown in this report:

- a minimum case,
- the expected (or most likely) case, and
- a maximum case.

Four factors are distinguished as main determinants of future developments in supply, the relative significance of each differing greatly from one supply category to another. The four factors are:

- Geological limitations; determine the probability of the resource being present and in what volume. This would be the controlling factor, for example, in forecasting crude oil discoveries. For the expected case the ultimate reserves included are those that are considered on geological grounds to have at least a 50 percent or better geological probability of existing. For the minimun case a 90 percent probability is used, and for the maximum case a 10 percent probability is employed.
- Technological limitations; influence the accessibility of resources to exploitation, the level of recovery from deposits, or the lead times required for development. This factor could be dominant for some types of enhanced recovery methods or in the production of frontier crude oil. For the expected case a gradual improvement in current technology is assumed. The minimum case assumes no significant technological advances, while the maximum case envisages major technological breakthroughs.
- Crude oil prices; can affect the rate of resource exploitation, and can influence recovery levels. For all cases it was assumed that domestic prices would approach international levels by 1980. For the expected case it was assumed that the international price would remain constant in real terms, i.e., that future international price increases would vary with inflation rates. For the maximum case it was assumed that international prices would increase five percent annually in real terms, and in the minimum case it was assumed that international oil prices would stay near current levels, i.e., they would decrease in real terms.
- Government policy; can affect development through availability of permits and licences, through regulations governing exploration and production practices, and through regulations affecting the availability of export and domestic markets for a crude stream. The way in which this factor is handled is discussed more fully under Views of the Board for each supply category mentioned previously.

ESTABLISHED RESERVES IN CONVENTIONAL AREAS

Views of Submittors

The views of submittors regarding this category of reserves were mainly embodied in completed forecasts for individual pools showing producibility and reserves estimates in the form requested by the Board in its Outline for Submissions (Appendix B). These forms made provision for the display of an oil producibility forecast to 1995 with sufficient reservoir data to support the forecast and to indicate the possibility of reserves appreciation. The Board requested these data from the major operators of some 200 individual pools and pool groupings. Independent estimates were received from the British Columbia Energy Commission ("B.C. Energy Commission"), the Alberta Energy Resources Conservation Board ("AERCB" or "Alberta Board"), and the Government of Saskatchewan ("Saskatchewan"). Completed data forms were received regarding all pools listed in the Outline for Submissions. Provincial agencies provided 100 percent coverage of the pools in their province, and data were received from the major operators of some 85 percent of the pools. The Canadian Petroleum Association ("C.P.A.") provided a summary of the industry pool forecasts.

Evidence contained in the submissions was supplemented by verbal testimony in response to questions at the hearing.

The individual pool data obtained through submissions and testimony are not shown in this report, but

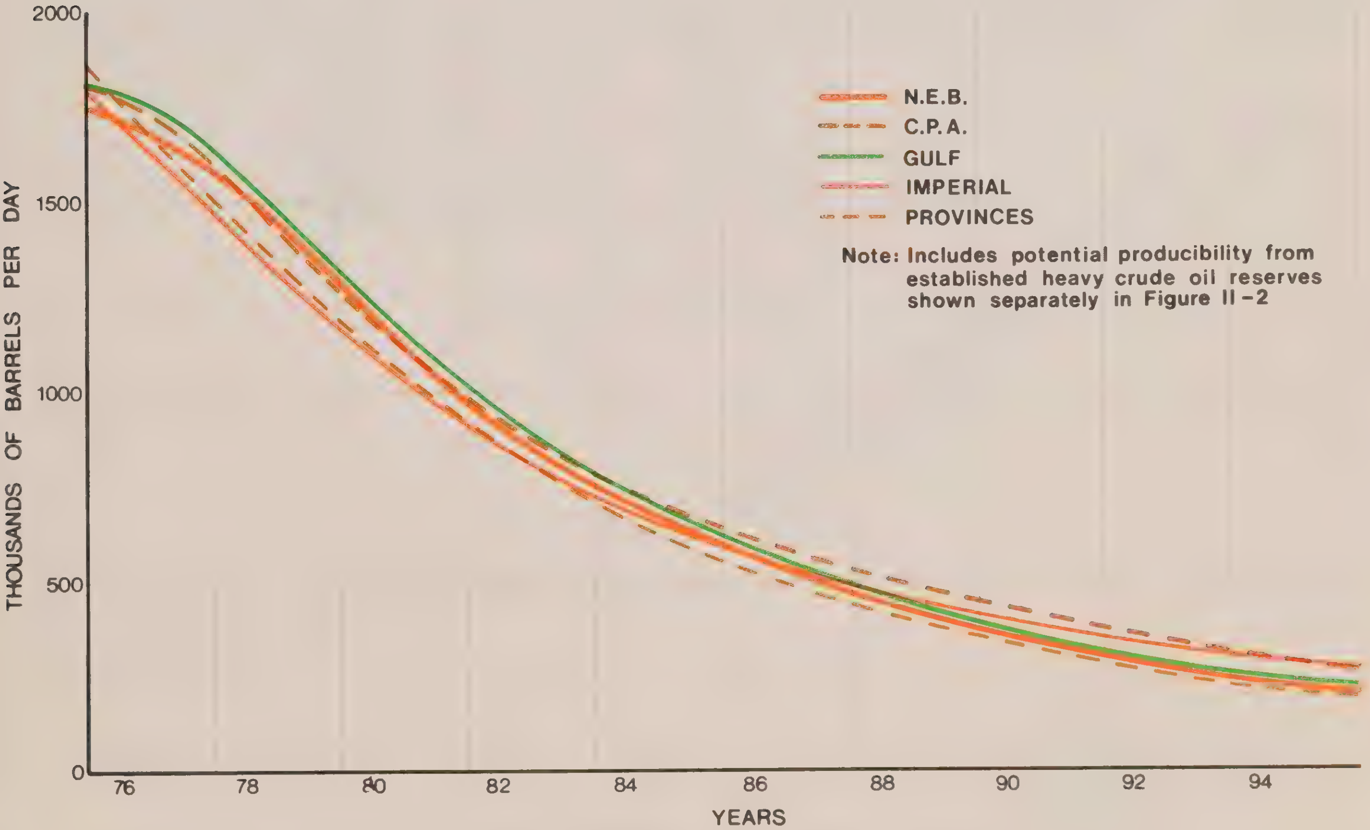


Figure II-1. **POTENTIAL PRODUCIBILITY FROM ESTABLISHED RESERVES**
Comparison of Forecasts

they are available for public inspection at the Board's offices in Ottawa and Calgary.

In addition to the summary forecasts received from the Provinces and the C.P.A., total potential producibility forecasts were received from Gulf Oil Canada Limited ("Gulf") and Imperial Oil Limited ("Imperial"). These forecasts are compared in Figure II-1. An analysis of the reserves estimates and producibility forecasts reveals little difference from last year's submissions.

A number of submissions dealt in specific terms with the potential producibility of heavy crude oil. Comparison of these forecasts is difficult because submittors were not consistent in their definitions of heavy crude oil. The Board has adjusted these potential producibility forecasts to include those pools classified by the Board as heavy crude oil pools, and the resulting forecasts are shown in Figure II-2. The Board's definition of heavy crude oil is given in Chapter VI (Table VI-I).

Views of the Board

The Board has taken into account all reserves evidence received at the hearing in making its current estimates of established reserves. These estimates are shown in Appendix C on a pool-by-pool basis. Gross additions from 1 January 1975 to 1 January 1976 are estimated at some 101 million barrels. Production during that same period is estimated at 504.6 million

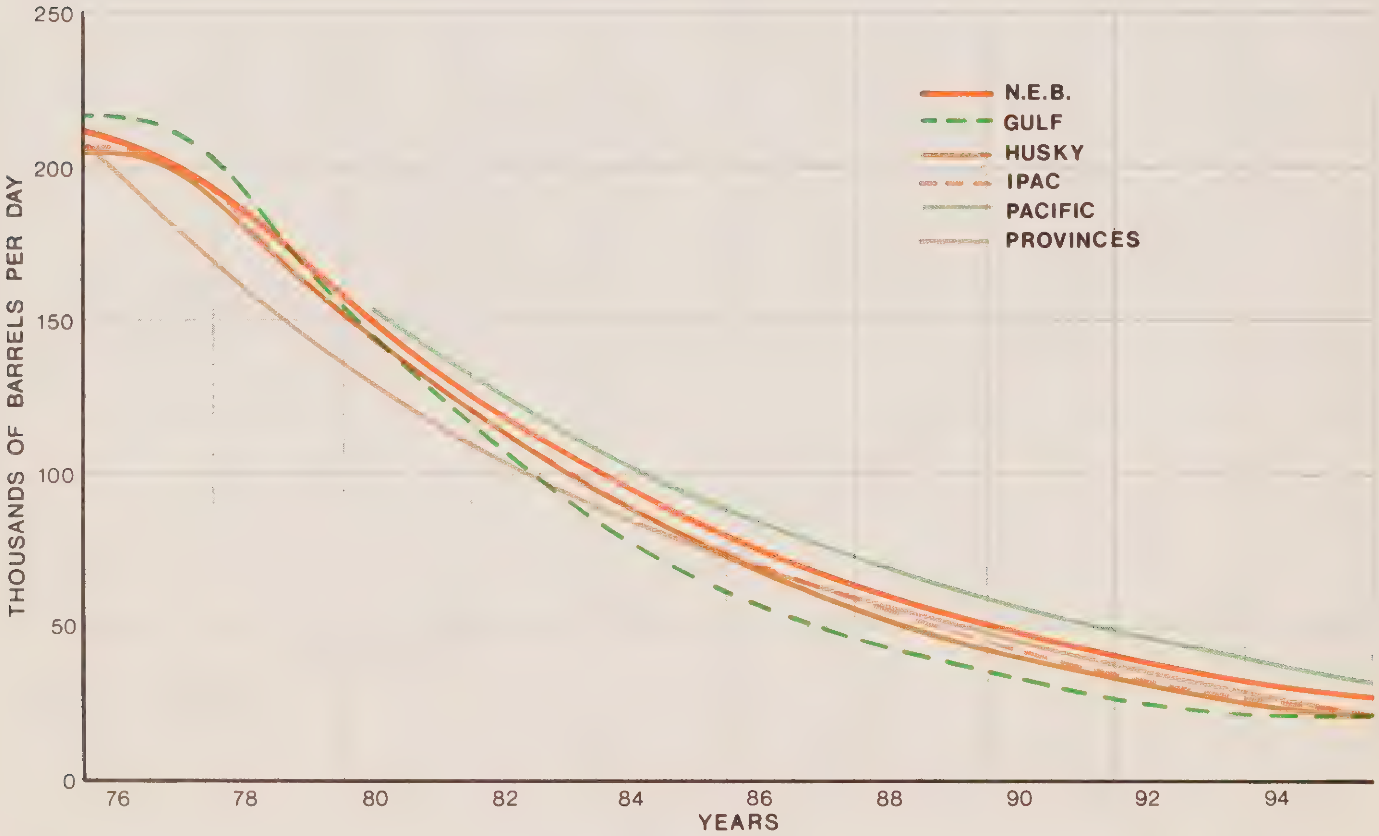


Figure II-2. **POTENTIAL PRODUCIBILITY FROM ESTABLISHED HEAVY CRUDE OIL RESERVES**
Comparison of Forecasts

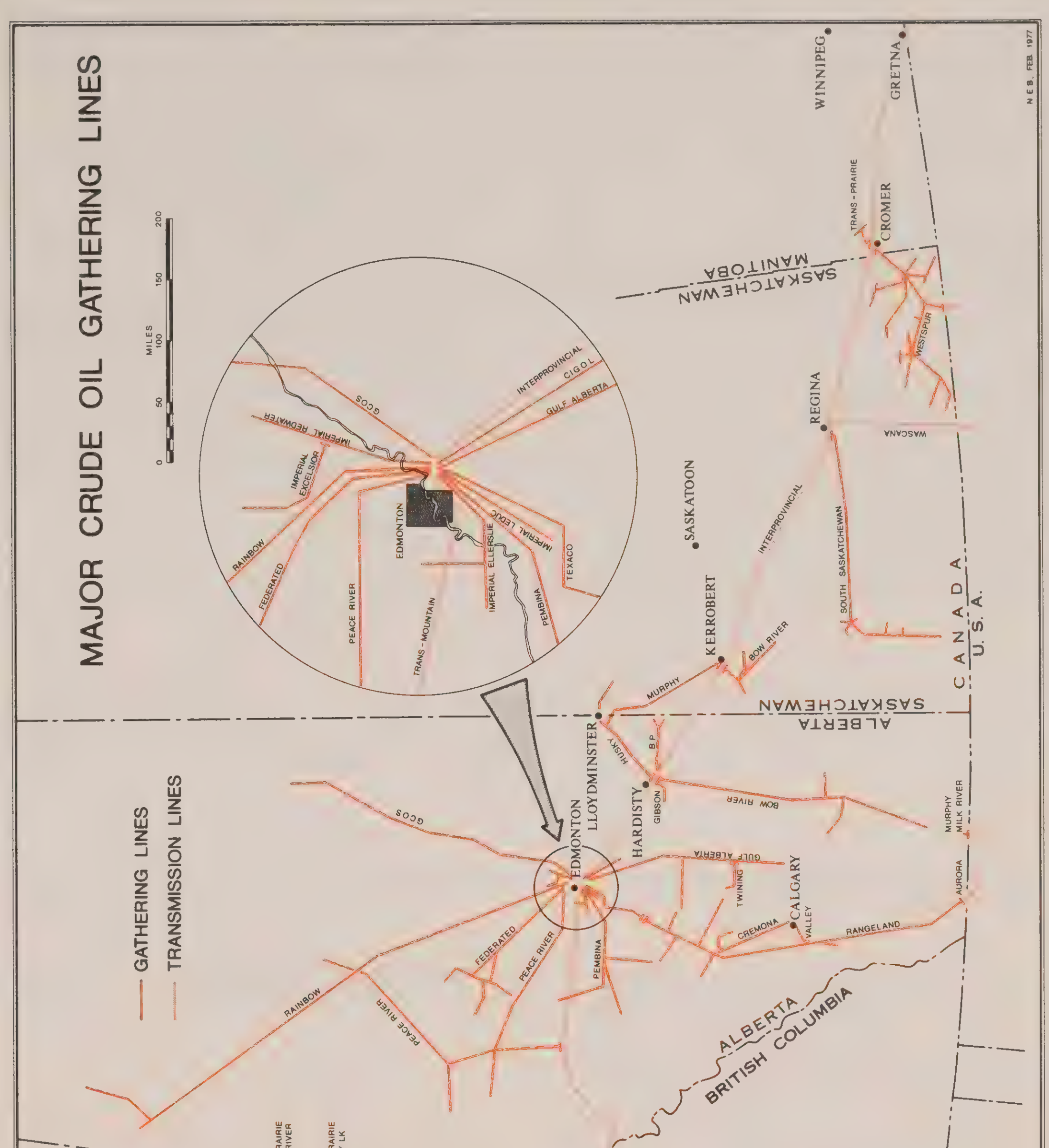


Figure II-3. **MAJOR CRUDE OIL GATHERING LINES**

barrels, resulting in a net reduction of remaining reserves of 403.6 million barrels. The pool-by-pool reserve data in Appendix C are grouped by pipeline system. The location of these pipelines is shown in Figure II-3.

The methods and computer models used by the Board to develop potential producibility forecasts were completely documented in the 1974 and 1975 oil reports and are not further discussed here.

After considering all evidence received in the submissions and in verbal testimony, together with information supplied after the hearing, the Board has developed the 20-year pool-by-pool potential producibility forecasts shown in Appendix D. This year the producibility table is divided into two sections dealing separately with light crude oil and heavy crude oil. The Board's forecasts are compared with the submitted forecasts in Figures II-1 and II-2.

The current forecast of total potential producibility from established reserves is compared to the September, 1975 forecast in Figure II-4.

The four factors discussed at the beginning of the chapter are felt to have little effect on the calculation of reserves currently considered as established. The major effects that they would have on existing reservoirs are considered under the section "Additions to Established Reserves in Conventional Areas". With regard to producibility, the existing surplus productive capacity makes unlikely any major increase in this capacity.

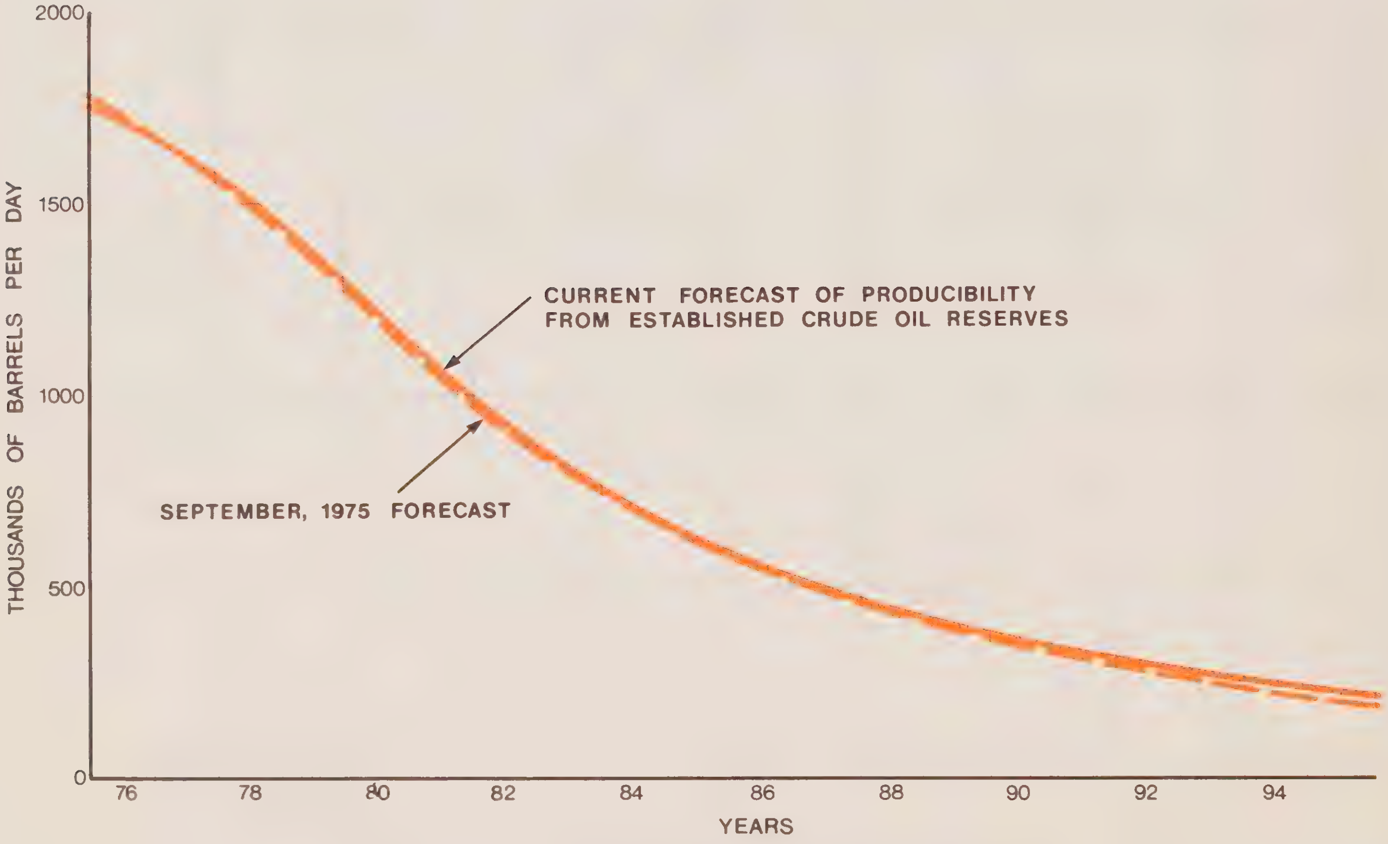


Figure II-4. **POTENTIAL PRODUCIBILITY FROM ESTABLISHED RESERVES**
NEB Forecasts

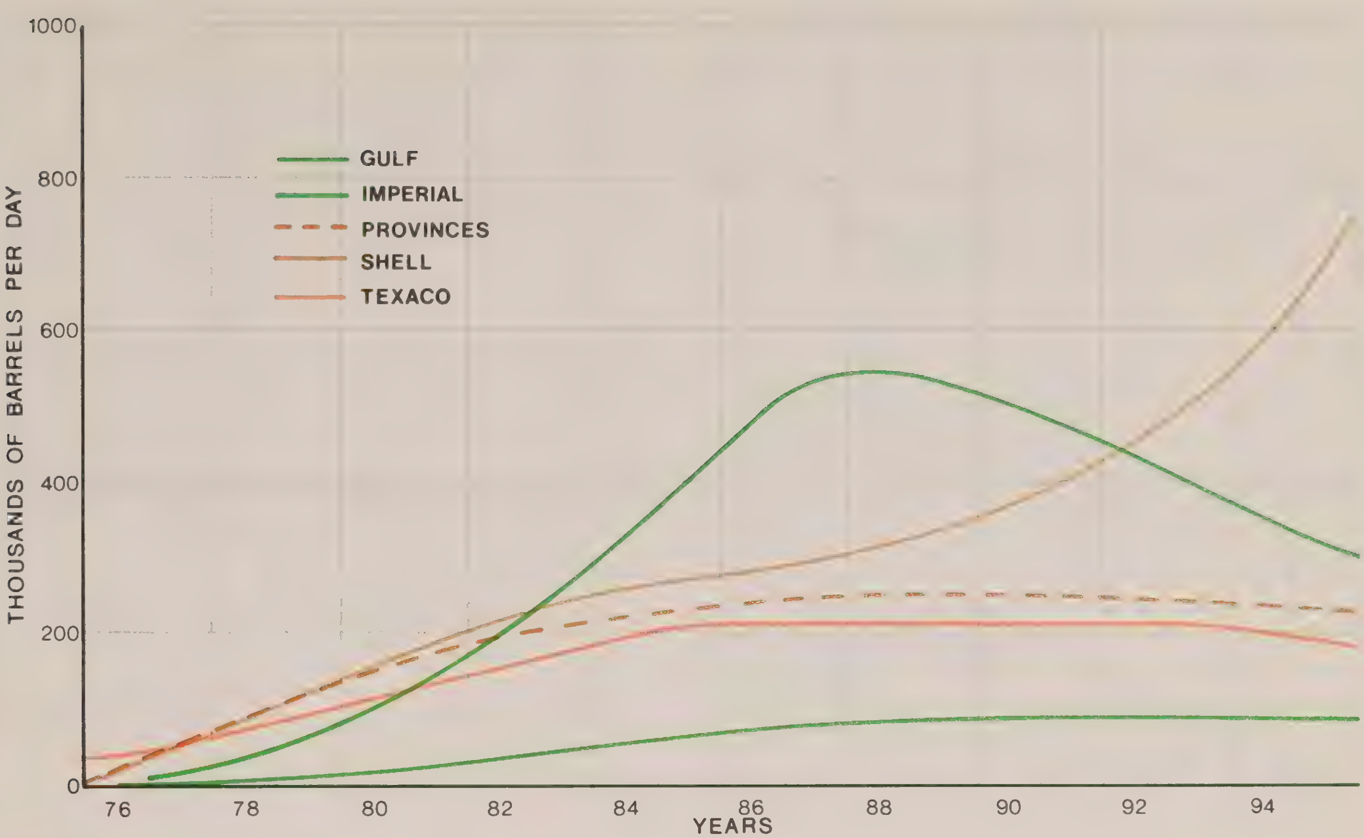


Figure II-5. **POTENTIAL PRODUCIBILITY FROM ADDITIONS TO ESTABLISHED RESERVES**
Comparison of Forecasts

ADDITIONS TO ESTABLISHED RESERVES IN CONVENTIONAL AREAS

Views of Submittors

The forecasts of potential producibility from additions to established reserves filed at the hearing are summarized graphically in Figure II-5.

At the Board's 1975 hearing there appeared to be a consensus that reserves additions would accrue largely from improved recovery methods as opposed to new discoveries. That remained the concensus at the current hearing. Although appreciation of discovered pools and waterflooding still have significant potential, most of the reserves additions attributable to improved recovery are expected to result from the application of tertiary recovery methods. Most companies which appeared at the hearing are currently evaluating application of tertiary recovery techniques, either through computer model development, laboratory work or field pilot schemes. Since most work is still directed at establishing feasibility, most producers said they were unable, at this time, to provide meaningful estimates of financial returns which would make these schemes economically attractive.

Imperial presented an analysis by geological horizon of the potential for enhanced recovery in the Southern Basin. Three tertiary processes were examined; CO_2 miscible flooding, surfactant (chemical) flooding, and wet combustion. Maximum recovery potential was put at 2.3 billion barrels for these three processes, but only some 1.8 billion barrels could be recovered at current world prices even without royalties or taxes. Ultimate potential from new discoveries was estimated to be about 0.5 billion barrels.

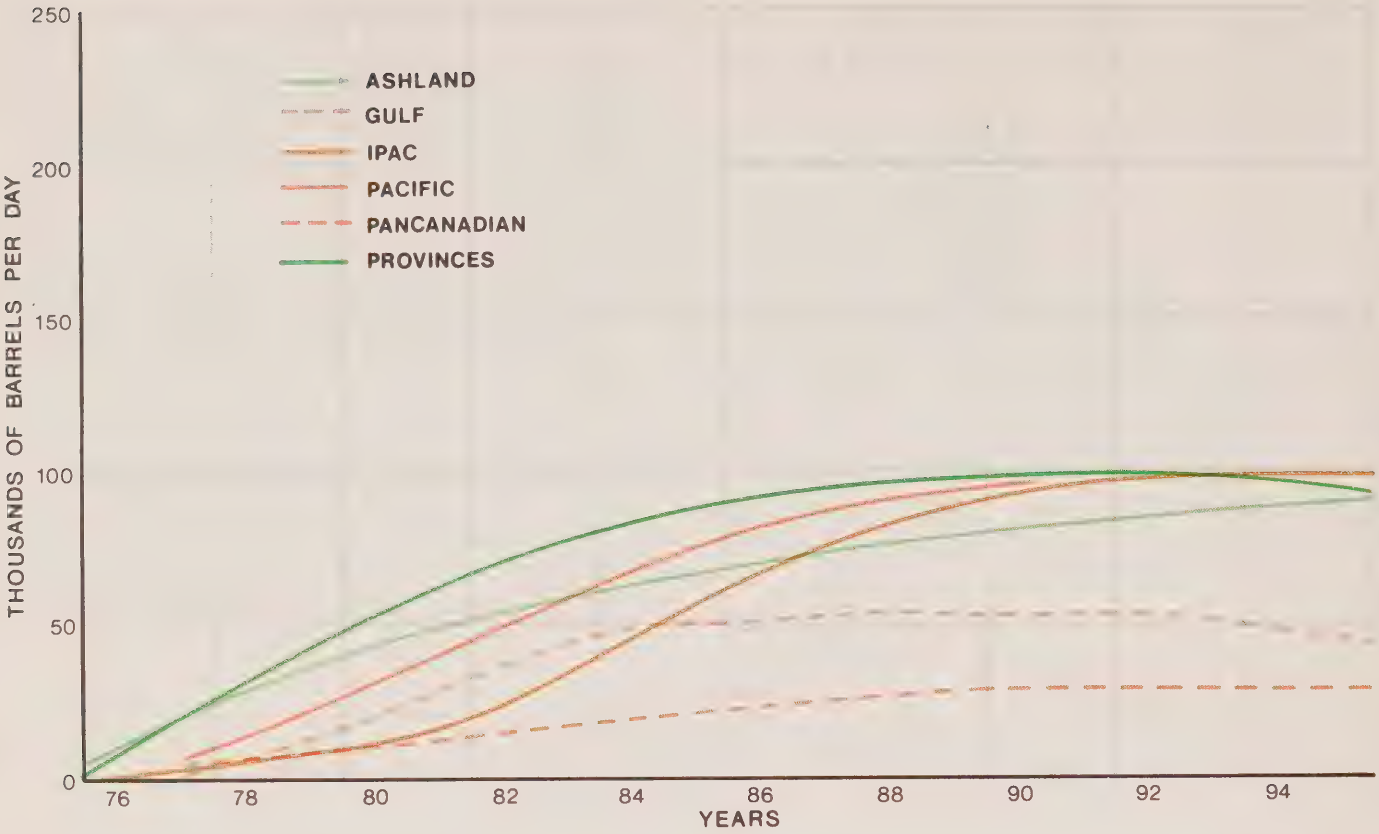


Figure II-6 **POTENTIAL PRODUCIBILITY FROM ADDITIONS TO ESTABLISHED HEAVY CRUDE OIL RESERVES**
Comparison of Forecasts

In a study prepared for the Board, and submitted as evidence at the hearing, D & S Petroleum Consultants (1974) Ltd. ("D&S") estimated potential tertiary reserves at some 2.9 billion barrels.

The AERCB estimated that the fraction of reserves growth in Alberta attributable to enhanced recovery operations will increase from some 30 percent to 80 percent during the forecast period. Combined reserves additions from new discoveries and improved recovery were kept fairly constant at 150 to 155 million barrels annually throughout the 20 year period resulting in a 20 year cumulative of some 3 billion barrels. Saskatchewan estimated reserves additions in the Province during the same 20 year period at 460 million barrels. The B.C. Energy Commission forecast 9 million barrels of reserves additions for British Columbia.

Shell Canada Resources Limited ("Shell") forecast the contribution of existing reserve appreciation and new discoveries at 0.47 and 2 billion barrels respectively. Potential supplementary recovery was notionally estimated at an additional 6 billion barrels (12 percent of 48 billion barrels original oil-in-place).

Several submittors provided separate forecasts of reserves additions for heavy crude oil. The submitted forecasts for potential producibility from additions to established reserves of heavy crude oil are compared graphically in Figure II-6.

There was a consensus that the heavy crude oil areas, and in particular the Lloydminster area, have a significant potential for new discoveries. Husky Oil Operations Ltd. ("Husky") stated its view that a conservative estimate of ultimate potential in the Lloydminster area is 12 billion barrels of original oil-in-place. Some 4 billion barrels of this is currently considered as proved.

In consideration of the lower than average primary and waterflood recovery levels in heavy crude oil reservoirs, (as low as 5 to 8 percent of original oil-in-place in Lloydminster-type pools) significant potential was credited to enhanced recovery operations. The Independent Petroleum Association of Canada ("IPAC") estimated this potential at 1.1 billion barrels and new discovery potential at 0.3 billion barrels. Using equations provided by Pacific Petroleums Ltd. ("Pacific"), the Board has calculated that company's estimate of enhanced recovery potential as 0.6 billion barrels, and new discovery potential as 0.9 billion barrels.

Views of the Board

The Board has examined the evidence regarding improved recovery potential, and in conjunction with its own studies has evaluated each established oil reservoir in Canada for improved recovery potential.

The results are summarized in Table II-1. The table also includes estimates of potential from new discoveries. Table II-2 provides additional detail regarding improved recovery potential for the expected case.

For the expected case, improved recovery potential is estimated at 2.07 billion barrels. About one-quarter of this total (0.53 billion barrels) accrues from waterflooding and infill drilling. The remaining three-quarters (1.54 billion barrels) results from the application of tertiary recovery methods. It can be seen from Table II-1 that at current world prices, one-half of the improved recovery potential is credited to heavy crude oil reservoirs. The Board believes that these developments will occur provided that prices approach international levels, and that markets are available for the heavy crude oil production. Regarding miscible and chemical projects, it was assumed for the expected case that current royalty/tax arrangements would be modified to make some of these projects economic.

Table II-1

RESERVES ADDITIONS POTENTIAL FOR CRUDE OIL
(billions of barrels)

		Minimum Case	Expected Case	Maximum Case
HEAVY CRUDE OIL	• New Discoveries	.32	.62	.90
	• Improved Recovery	.63	1.09	1.48
	Total	.95	1.71	2.38
LIGHT CRUDE OIL	• New Discoveries	.20	.48	.80
	• Improved Recovery	.32	.98	1.63
	Total	.52	1.46	2.43
ALL CRUDES	• New Discoveries	.52	1.10	1.70
	• Improved Recovery	.95	2.07	3.11
	Total	1.47	3.17	4.81

Table II-2

IMPROVED RECOVERY POTENTIAL FOR CRUDE OIL BY FORMATION AND METHOD
(Expected case — billions of barrels)

		Improved Recovery Method					
	Formation	Chemical Flooding	Infill Drilling	Miscible Flooding	Thermal Techniques	Waterflood	Total
CRETACEOUS	• Cardium	.15	.02	—	—	.02	.19
	• Mannville (High Gravity)	.03	.01	.01	.08	.08	.21
	• Mannville (Low Gravity)	—	.03	—	.46	.07	.56
	• Other	.05	.00	—	.03	.07	.15
	Total	.23	.06	.01	.57	.24	1.11
JURASSIC	— Total	.04	.02	—	.08	.02	.16
TRIASSIC	— Total	.06	.01	.07	—	.00	.14
MISSISSIPPIAN	— Total	.02	.03	.21	.06	.07	.39
DEVONIAN	• Woodbend	—	.00	.02	—	.01	.03
	• Beaverhill Lake	—	.04	.04	—	.00	.08
	• Elk Point, Gilwood	—	.03	.13	—	—	.16
	Total	—	.07	.19	—	.01	.27
TOTAL ALL FORMATIONS		**.35**	**.19**	**.48**	**.71**	**.34**	**2.07**

The new discovery potentials shown in Table II-1 include new fields and extensions to discovered reservoirs. In the case of light crude oil, new discoveries were assigned a recovery factor approximating combined primary and secondary recovery levels. In the case of new heavy crude oil discoveries, some recognition was given to thermal methods in the Lloydminster area.

The following two sections provide additional views on the reserves additions potential for heavy crude oil and light crude oil respectively.

HEAVY CRUDE OIL: It is the Board's view that there is an adequate geological potential to double the currently established reserves of heavy crude oil through a combination of new discoveries and improved recovery. As shown in Table II-1, nearly two-thirds of the 1.71 billion barrels of potential forecast results from improved recovery from discovered reservoirs. Operators of thermal projects in the Lloydminster area generally agreed that with the recent oil price increases these projects have now become marginally economic. The Board believes that expected future increases in wellhead prices and corresponding improvements in producer returns should make these projects economically attractive. However, the lead time required for the evolution of required technology will control the rate of implementation of projects.

Table II-3

IMPROVED RECOVERY POTENTIAL FOR HEAVY CRUDE OIL BY METHOD (billions of barrels)

	Minimum Case	Expected Case	Maximum Case
• Chemical Flooding	.01	.04	.06
• Infill Drilling	.05	.06	.07
• Miscible Flooding	.00	.11	.28
• Thermal Techniques	.43	.68	.86
• Waterflood	.14	.20	.21
Total	**.63**	**1.09**	**1.48**

Table II-4

IMPROVED RECOVERY POTENTIAL FOR LIGHT CRUDE OIL BY METHOD (billions of barrels)

	Minimum Case	Expected Case	Maximum Case
• Chemical Flooding	.13	.31	.47
• Infill Drilling	.08	.13	.18
• Miscible Flooding	.00	.37	.76
• Thermal Techniques	.01	.03	.05
• Waterflood	.10	.14	.17
Total	**.32**	**.98**	**1.63**

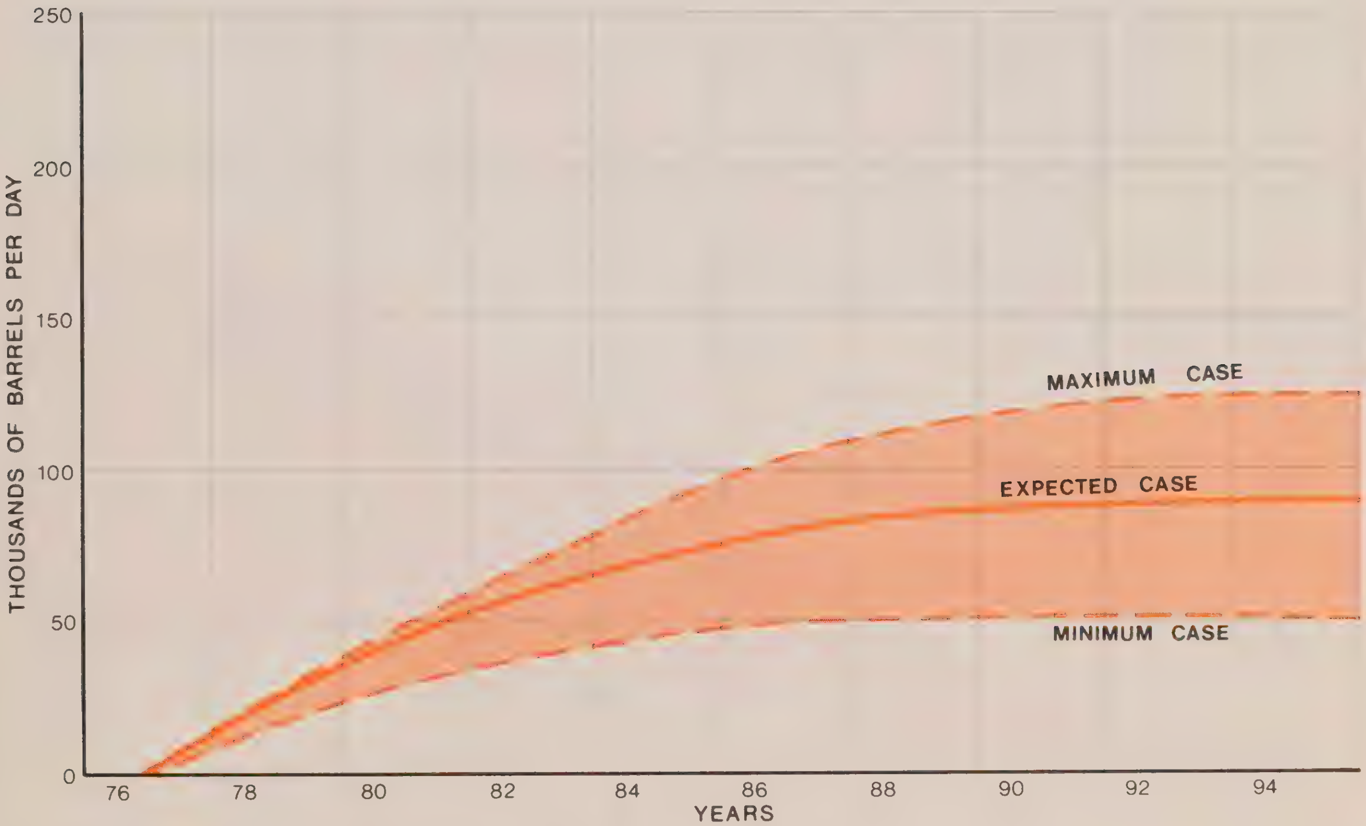


Figure II-7. **POTENTIAL PRODUCIBILITY FROM ADDITIONS TO ESTABLISHED HEAVY CRUDE OIL RESERVES**
NEB Forecast

Table II-3 shows the Board's estimate of heavy crude oil improved recovery potential by method.

Estimates of potential producibility from additions to established heavy crude oil reserves are shown in Figure II-7.

LIGHT CRUDE OIL: The disappointing exploration results during the last ten years lead the Board to adopt a fairly conservative estimate for new discoveries of light crude oil as shown in Table II-1.

The majority of reserves additions to light crude oil are expected to accrue from improved recovery. Table II-4 shows a breakdown of light crude oil improved recovery potential by recovery mechanism.

An estimate of potential producibility from additions to established reserves of light crude oil is provided in Figure II-8.

PENTANES PLUS

Views of Submittors

The views of submittors regarding this class of reserves were principally detailed in forecasts for individual natural gas processing plants in the form requested by the Board in its Outline for Submissions. In addition, Shell, Gulf, and Imperial submitted forecasts of production from established reserves and from reserves additions for Canada as a total. The AERCB provided forecasts of production from established reserves grouped by gas plant (or area), and

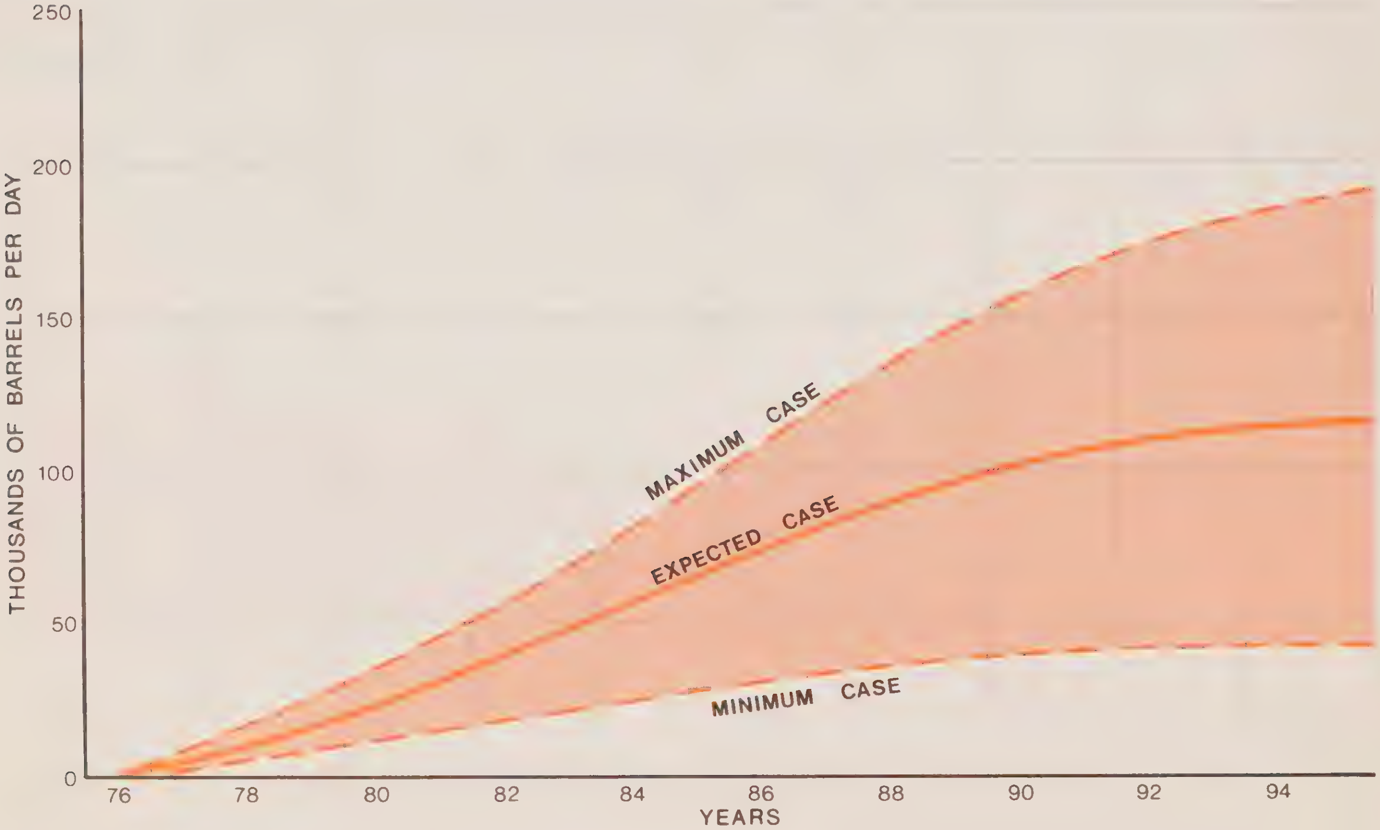


Figure II-8. **POTENTIAL PRODUCIBILITY FROM ADDITIONS TO ESTABLISHED LIGHT CRUDE OIL RESERVES**
NEB Forecast

pipeline and of production from Alberta reserves additions. The forecasts of pentanes plus production submitted to the Board are shown in Figure II-9. The forecasts shown include pentanes plus production from established reserves together with production from forecast reserves additions.

Views of the Board

To increase the accuracy of the pentanes plus forecast and to treat the submitted data in more detail, the Board has developed and uses a computer model which considers natural gas production on a pool-by-pool basis grouped according to the gas plant in which the gas is processed. Changes in pentanes plus yield with depletion of the reservoir, cycled gas volumes, as well as pentanes plus recovery efficiency of each processing plant are considered in the model.

In the light of the evidence received, the original list of plants was adjusted. Several plants were deleted and others added to give a final list of 49 plants or groups of plants (by field or area). These plants or groups of plants studied in detail accounted for about 90 percent of the Canadian production of pentanes plus in 1975. The remaining plants not studied were placed in "other" categories. A summary of the pentanes plus production forecast is shown in Appendix E.

In constructing a forecast of pentanes plus production from reserves additions, a forecast of natural gas deliverability from reserves additions was combined with a forecast of pentanes plus yields from these additions. Initial yields were estimated to be 15 barrels per million cubic feet of marketable gas, declining to 10 barrels per million cubic feet over a

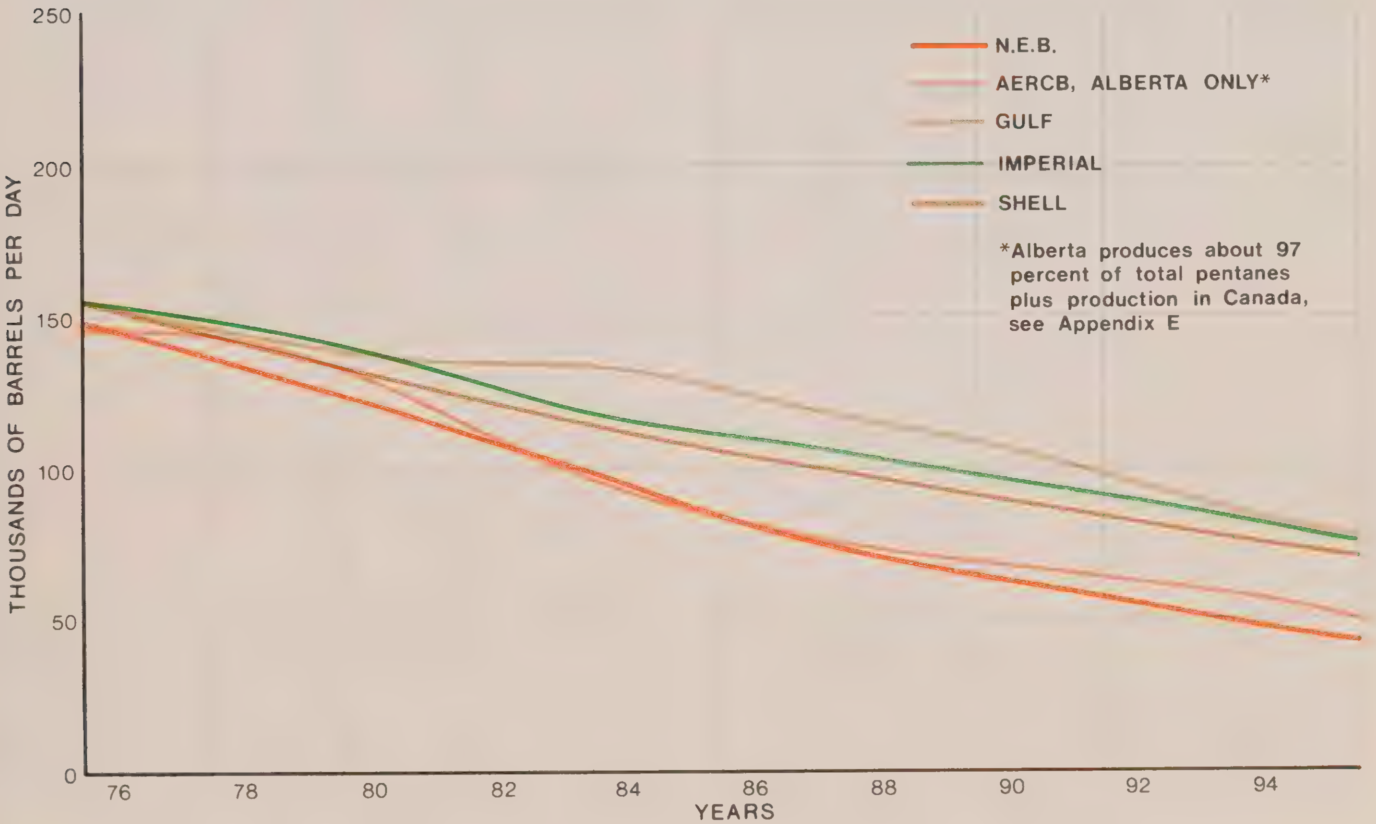


Figure II-9 **PRODUCTION OF PENTANES PLUS**
Comparison of Forecasts

period of 10 years and remaining constant at that value for the duration of the forecast period. This portion of the pentanes plus forecast also includes pentanes plus production from gas plants which are currently under construction. The Board's forecast of pentanes plus production from established reserves and reserves additions is shown in Figure II-9. As can be been from the graph, the Board's current forecast is in reasonable agreement with the AERCB forecast, but significantly below the industry forecasts. The Board's current forecast is also lower than the forecast published in its September 1975 report. While a portion of this reduction is due to poorer than expected performance in some pools, the greater part of the reduction is a result of the more detailed study related to this year's forecast.

OIL SANDS

Views of Submittors

Detailed oil sands producibility forecasts were received from five submittors. These forecasts are compared graphically in Figure II-10.

Shell submitted a forecast assuming no oil sands development beyond that from Great Canadian Oil Sands Limited ("GCOS"), Syncrude Canada Ltd. ("Syncrude"), and experimental in situ projects, producing a total of 184 Mb/d which is consistent with Shell's decision to shelve its oil sands development plans. At the 1975 hearing when Shell was still actively pursuing oil sands development it had projected producibility to increase to 735 Mb/d by

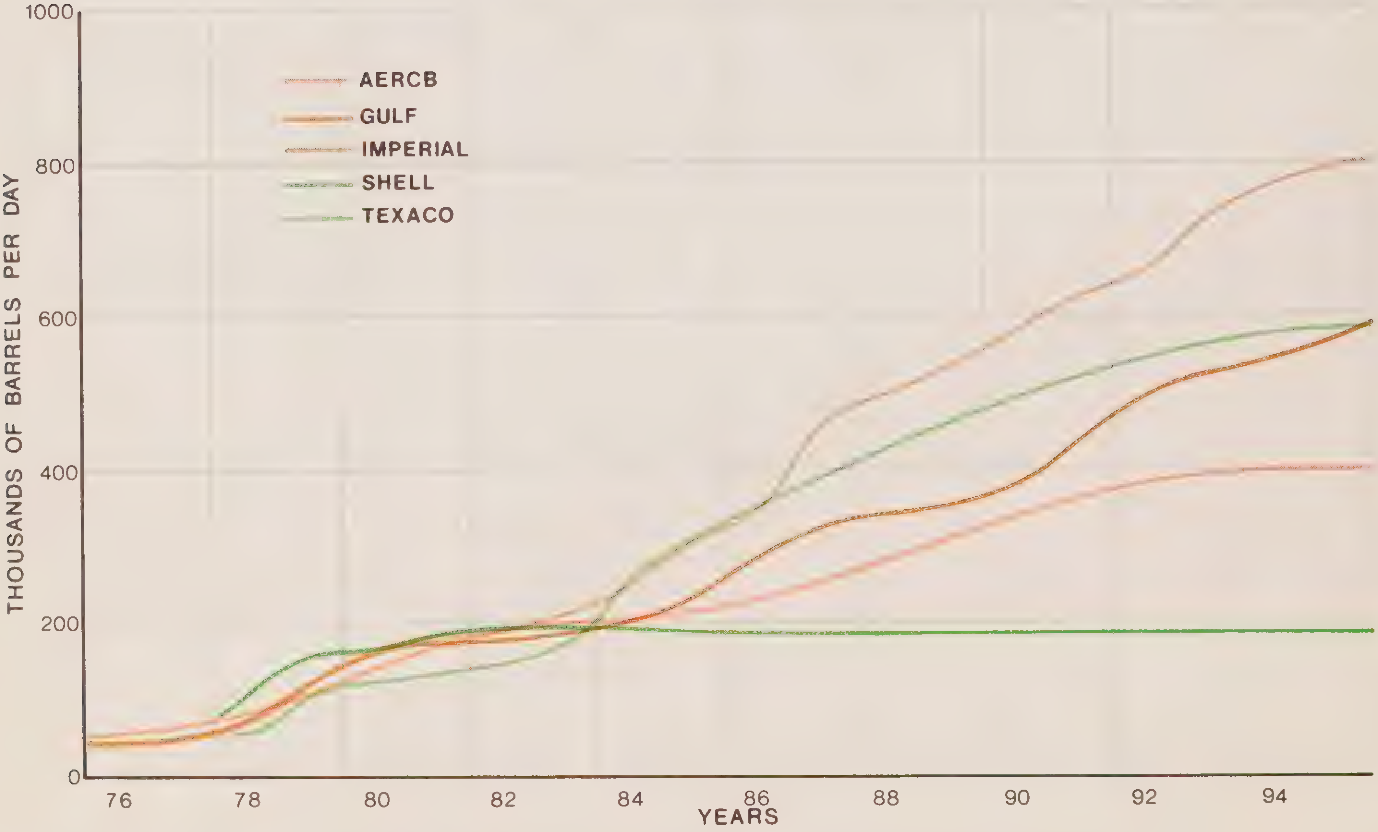


Figure II-10. **POTENTIAL PRODUCIBILITY FROM OIL SANDS**
Comparison of Forecasts

1994. Shell witnesses outlined three problem areas that must be resolved before additional plants could proceed; government assistance with financing, world oil prices for synthetic crude production, and substantially reduced (or no) government taxes and royalties. Construction costs for an oil sands plant were put at 2.4 billion dollars, and operating costs at $4.40 per barrel. Under these circumstances and assuming no royalties and taxes Shell feels it could produce synthetic crude oil at just less than the current international oil price. Also, if its project (mining project #3) received approval in 1977, it could be on stream by 1986.

The AERCB submitted a minimum development forecast which included only two commercial projects after Syncrude: a third mining project (commencing production in 1987) and an in situ project (commencing production in 1990). The AERCB assumed that the upgrading facility of this in situ project would also upgrade all heavy crude oil from various experimental in situ schemes which amounted to 25 Mb/d by 1989. Total production was forecast to reach 400 Mb/d by 1995. This is below the lower of the two development scenarios submitted by the AERCB at the 1975 hearing which showed production reaching 540 Mb/d by 1994. The AERCB estimated original bitumen in place at 953 billion barrels and estimated recoverable reserves of crude bitumen at 38 billion barrels, equivalent to 26.6 billion barrels of synthetic crude oil. The AERCB stated that the proved reserves of crude bitumen which are recoverable by surface mining would be theoretically adequate to support 20 to 30 plants of today's size without requiring the development of new technology other than some improvements to mitigate the environmental impact. However, the current economic conditions which limit the availability of capital were seen as a serious impediment to oil sands development. These economic conditions include rapid increases in costs, marketing uncertainties, and expected net revenues flowing back to the developer. In situ production was seen as having great potential in the longer term, perhaps starting within the next decade. The AERCB stated a belief that production could be developed much more rapidly and reach some 800 Mb/d by 1995 if both industry and the governments involved proceed on an aggressive development plan.

Gulf anticipated three more commercial size projects after Syncrude: a third mining project in 1985, a fourth mining project in 1990, and an in situ project in 1991. Total production, including 40 Mb/d from experimental schemes, was predicted to reach 575 Mb/d by 1995. This was consistent with the forecast submitted by Gulf a year ago which showed production reaching 565 Mb/d by 1994. Gulf stressed that the forecast was speculative and subject to many uncertain factors including synthetic crude oil prices, cost inflation, royalties, and in the case of in situ, the evolution of technology. Gulf estimated the cost of Syncrude at 2.5 billion dollars, and predicted that future plants would run well over 3 billion dollars. International oil prices (or better) and a reduction in government take are required for the forecast to materialize.

Texaco Canada Limited ("Texaco") submitted a forecast which assumed four additional projects after Syncrude to come on stream in each of the years 1984, 1987, 1990 and 1993. This would bring production levels to 590 Mb/d by 1995. The forecast was considerably reduced from the one submitted last year which had production increasing to 740 Mb/d by 1995. Texaco assumed that the necessary incentives for additional plants to come on stream as forecast would be provided by changes in the current oil sands tax and royalty regulations.

Imperial submitted a potential development forecast which included five additional projects after Syncrude: a Syncrude expansion in 1983, followed by new mining projects in 1985, 1990 and 1993, an in situ project in 1987, and some 15 Mb/d from in situ pilots. With this schedule production would reach 799 Mb/d by 1995. Imperial emphasized however, that under existing price and revenue sharing conditions, continued production from only the GCOS and Syncrude ventures was assured. Imperial stated that world oil prices and improved revenue sharing conditions are required to achieve its potential development scenario. Imperial felt that the risk of a mining project encountering serious operating problems may affect investment in a third mining plant or in a Syncrude expansion. It was also Imperial's opinion that economic in situ recovery technology has not

been confirmed, but it remained optimistic that within three to five years the technology which is currently being tested would be accepted as proved.

Views of the Board

The Board is convinced that the oil sands development rate shown in its September 1975 report will not be achieved and a significant downward adjustment is called for.

Mining Projects

Only the shallower part of the Athabasca oil sands deposit is suitable for surface mining. According to AERCB estimates about 38 billion barrels of bitumen of this huge deposit are recoverable by this method. This volume of bitumen is equivalent to 26.6 billion barrels of synthetic oil. The Board accepts the AERCB estimates and concludes that reserves will not be a limiting factor in the development of mining projects during the 20 year forecast period.

Technology is not a major problem either, but it is the Board's view that evolving technology can have an effect on the timing of the projects. Investors may be hesitant to commit large sums of capital for additional mining projects before seeing a successful start-up of the Syncrude plant. Furthermore, the Alberta Government may wish to delay approval of new projects until the responsible authorities have a better appreciation of the environmental and socio-economic impact of the Syncrude project.

The major problem remains one of economic and financial feasibility. With future synthetic crude oil production priced at international oil prices, the most critical assumption affecting economic feasibility is the relationship of future world oil prices to general cost inflation. A less critical but nevertheless very important economic assumption relates to future government royalty and income tax arrangements.

On the assumption there will be some improvement in economic conditions and on the basis of the evidence presented at the hearing, the Board considers it reasonable to expect that a third mining project could be on stream by 1987. A fourth mining project could be completed four years later in 1991. These estimates are shown as the expected case in Appendix F.

In Situ Production

Most of the oil sands deposits lie at depths suitable only for in situ recovery methods. In this case development of suitable technology is considered as important as economic factors. Several in situ pilot projects are currently producing a total of some 5 Mb/d. The Board's forecast for in situ pilot production is shown in Appendix F. Under all three development scenarios production increases up to the period 1983-1985. After this time, production stabilizes under the maximum and expected development cases and declines to current levels under the minimum development case. These pilot projects are required to evaluate the feasibility of a recovery technique in selected areas of the oil sands before committing funds to a commercial scheme. With a minimum period of three to five years to evaluate current pilots and a six to seven year period to design and construct a commercial scheme, at least a decade will elapse before any commercial in situ scheme could be in operation. Although it is impossible to evaluate the economics of an undeveloped technology, there appears to be a consensus that in situ oil sands production will be at least as expensive as production from surface mining operations. Appendix F contains the Board's notional forecasts regarding the timing of in situ projects under the three development scenarios.

Summary

The combined mining and in situ forecasts of Appendix F are shown graphically in Figure II-11. The oil sands producibility forecast of the previous report is superimposed on Figure II-11 to show the magnitude of the downward revision in anticipated oil sands development. Only the forecast identified as the expected case is included in crude oil and equivalent forecasts in the balance of this report. Although estimation of future oil sands development

is less certain than forecasting production from established reserves, it is important to remember that the timing of these projects has no effect on the calculation of the level of crude oil exports, since the predicted domestic shortfall occurs well before any possible start-up date for a third project.

FRONTIER RESERVES

Views of Submittors

A summary of the information regarding frontier oil producibility which was submitted is shown in Table II-5. In all cases the estimates are considerably more conservative than data provided to the Board last year by the same companies.

Oil potential for the Mackenzie Delta-Beaufort Sea area has been substantially reduced since last year. Imperial for example, has revised its estimated date of earliest production from 1983 (in last year's submission) to after 1995 (this year's submission).

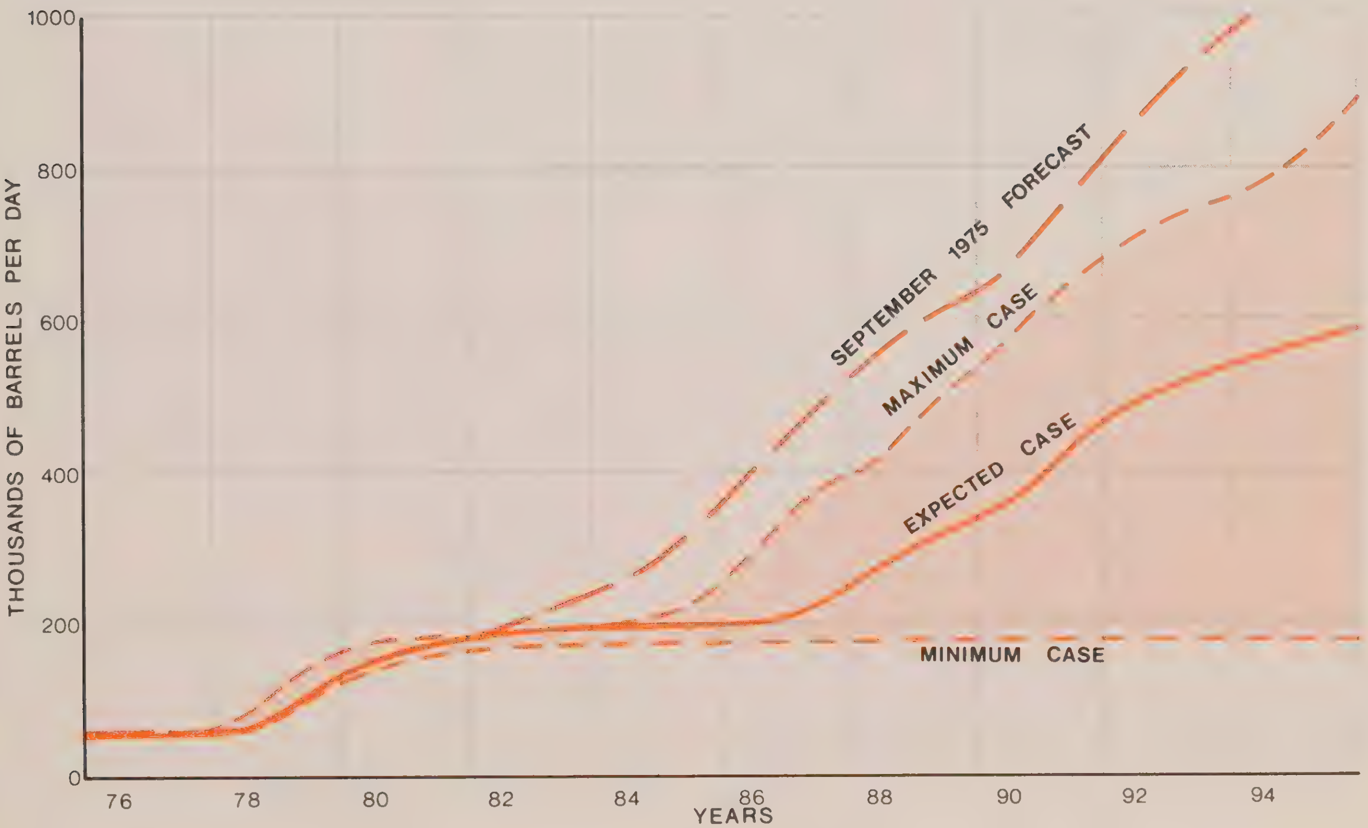


Figure II-11. **POTENTIAL PRODUCIBILITY FROM OIL SANDS**
NEB Forecast

TABLE II-5

RESERVES POTENTIAL ESTIMATES FOR FRONTIER CRUDE OIL
(Reserves in billions of barrels)

	MACKENZIE DELTA BEAUFORT SEA			ARCTIC ISLANDS			EAST COAST		
	Discovered to Date	Ultimate Potential	Year of First Production	Discovered to Date	Ultimate Potential	Year of First Production	Discovered to Date	Ultimate Potential	Year of First Production
GULF	.25 to .50	6	1986	–	–	–	–	15	1986
IMPERIAL	? (.1 by Imperial)	3.5	After 1995	–	–	1986	–	15	1991
MOBIL	–	5 (by 1995)	Late 1980's	–	–	–	–	1.9 (by 1995)	1985
SHELL	.25 (.13 by Shell)	6	–	–	–	–	–	–	–

Imperial has placed the ultimate potential at 3.5 billion barrels, and estimates that 2/3 to 3/4 of that volume will be offshore where the physical production problems still have to be solved. Gulf witnesses were the most optimistic, estimating an ultimate potential of 6 billion barrels, and a pipeline to be in operation by 1986.

Little data was received regarding oil potential for the Arctic Islands. Panarctic Oil Ltd. ("Panarctic") reported the results of production tests on three potential producing wells in the Bent Horn oil field at Cameron Island. However, it stated that the wells drilled to date afford inadequate data for the accurate determination of reserves.

The area with the highest ultimate potential estimates is the East Coast, with the best prospects appearing to be along the Labrador Shelf. If oil is found, production will be difficult to develop in this iceberg prone area. Significant potential was also credited to the greater water depths, 2000 to 6000 feet, but realization of this potential will require the development of new drilling and production technology.

Views of the Board

From evidence presented at the hearing, and from its own studies, the Board sees no reason to change its previously published finding that oil production from the frontier areas remains too speculative to warrant inclusion in a procedure designed to provide protection for Canadian requirements. It appears highly unlikely that any significant volume of frontier oil production could move to Canadian markets for domestic crude during the ten year period covered by the protection procedure.

SUMMARY OF POTENTIAL PRODUCIBILITY FORECASTS

A summary of the potential producibility forecasts of crude oil and equivalent for the expected case is provided in Appendix G. Shown are subtotals for light crude oil and heavy crude oil as they are normally marketed.

Figure II-12 graphically illustrates the contribution of each supply source to the availability of total crude oil and equivalent.

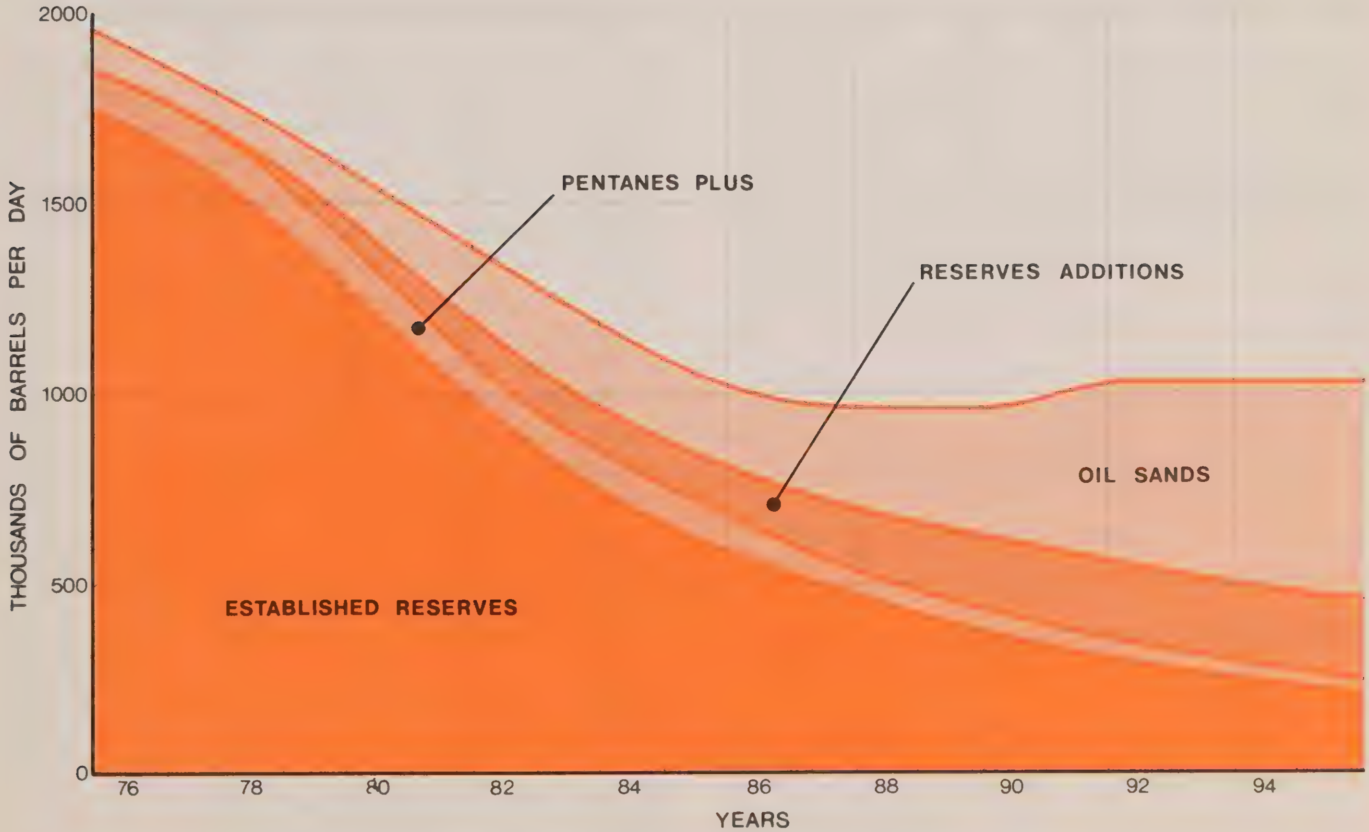


Figure II-12. **POTENTIAL PRODUCIBILITY OF CANADIAN CRUDE OIL AND EQUIVALENT NEB Forecast**

Demand for Total Energy

In the Outline for Submissions, submittors were requested to consider the demand for refined petroleum products in the context of the total energy outlook and interfuel competition. While the utilization of other energy forms was not considered in detail at the hearing, submittors were requested to provide sufficient information to permit comparative evaluation of the submitted forecasts of refined petroleum product demands. In making its own determination of Canadian demand for refined petroleum products, the Board has given consideration to the demand for other energy forms.

Of the thirty-seven submissions received, nineteen contained information on demand or demand forecasts. Some of the submittors who provided demand forecasts restricted themselves to the market areas or products with which they were primarily concerned. Four submittors — namely Gulf, Imperial, Shell and Texaco — provided forecasts of demand for all the major refined petroleum products for all the major regions in Canada.

Techniques employed by submittors and by the Board in forecasting energy demands, the assumptions used in generating the energy demand forecasts, and the resulting forecasts of sectoral energy demands are presented in this Chapter. The related forecasts of the demand for refined petroleum products as developed within these frameworks are discussed in Chapter IV. In Appendix K the forecast of energy demand and the underlying demographic and economic growth assumptions from this report are compared to the forecast presented in the Board's September 1975 report, and a projection published by the Department of Energy, Mines and Resources.

FORECASTING METHODS AND ASSUMPTIONS

Methodology

Views of Submittors

Gulf estimated total energy demand through statistical analysis of historical data and the relationship between total energy demand and Gross National Product ("GNP"). GNP projections were obtained from the Economic Council of Canada's CANDIDE model. Sector demands were determined by correlating residential demand with population, commercial demand with employment in the commercial sector, and industrial demand with the index of industrial production. The transportation sector was analyzed separately and incorporated into the larger study. Market shares by fuel-type and regional breakdowns were obtained using similar statistical analysis. Demand for refined petroleum products was further assessed using regression analysis modified by subjective judgment.

Imperial estimated demand by projecting economic factors to determine energy demand in the residential-commercial, industrial and transportation sectors in five major geographical regions. Historical patterns of energy use as derived were adjusted judgmentally to allow for projected improved energy-use arising from higher real prices and demand-reducing programs. Individual fuel shares reflect historical patterns and estimated future price relationships.

Shell's forecast was based on an integrated energy demand study linking energy demand by sector to economic indicators. In the residential sector, trends in population, persons per household, and space heating facilities were used to determine the space heating demand to which hot water heating and electrical uses were added. Commercial sector demands were based on correlations with commercial employment anticipated in other than the transportation and electric utility industries. Industrial sector demand for each province was determined by correlation with Gross Provincial Product ("GPP") modified for the anticipated effects of conservation measures and policies. In the transportation sector, motor gasoline was forecast utilizing a transportation model which considered automobile size, scrappage, efficiency and miles driven. Other energy transportation requirements were determined by correlation with GPP.

Texaco forecast Canadian primary energy consumption and refined petroleum product demands by analysing historical trends which were modified subjectively in consideration of forecasts of economic activity and conservation trends.

Views of the Board

In developing its estimates of the demand for refined petroleum products in Canada, the Board adopts a total energy approach for those sectors of demand where a variety of fuels is used. In the Board's method, forecasting of the demand for energy in these particular sectors of consumption is considered prior to and separately from the selection of fuel type. This procedure ensures consistency of the forecast demand for individual fuels with the forecast demand for total energy. The behaviour of the energy demand process versus the fuel selection process is analyzed separately in order to consider the different factors affecting each process.

The major end-use sectors which have been considered in forecasting energy requirements are the residential, commercial, industrial, petrochemical and transportation (including road, rail, air and marine) sectors.

In the residential, commercial and industrial sectors, demand for individual fuels is forecast by first determining total energy requirements in each sector. The total energy demand in each particular sector is estimated by equations which link energy demand to forecasts of economic activity, population, and energy prices. Then a set of market share estimates is applied to yield demands for individual fuels, including refined petroleum products, in each sector.

In the transportation sector energy demand is estimated separately for each of its various main segments namely, road, rail, air and marine. In each of these segments a model was developed incorporating the prime variables affecting demand. For example, automotive gasoline demand is forecast by estimating the stock of cars by age and weight class, and then applying estimated average miles driven and fuel economies per car according to type of car.

Chapter IV, entitled Demand for Refined Petroleum Products, incorporates some additional details of the Board's forecasting methodology and assumptions. Because of its importance, particular attention is given to the forecasting of the motor gasoline component. Further details of the methodology used for forecasting energy demand can be found in Appendix J.

The forecast of demand which, in the Board's judgement, is the most likely is referred to as Scenario I, or simply the Board's forecast. Given the uncertainties in predicting economic growth and future price levels of energy fuels, six scenarios were evaluated with the goal of estimating a range of Canadian energy demand over the forecast period. The scenarios combined three sets of price assumptions and two sets of values for economic growth. The six scenarios developed are employed in Chapter VIII to consider the variability in the requirements for crude oil and equivalent WOV. The assumptions underlying these scenarios are detailed in that chapter.

A fourth price assumption is used to develop the conservation factor for the purposes of the export formula. The development of this case is discussed in the final section of this chapter under the heading of "Energy Conservation and the Export Formula".

Demography

Views of Submittors

The various views as to the expected growth in the Canadian population are summarized in Table III-1. Gulf, Imperial and Texaco all adopted Statistics Canada's Population Projection B.

Table III-1

POPULATION GROWTH RATES
Comparison of Forecasts
(Percent per annum)

	Gulf Imperial Texaco	Shell	Sun	NEB
1975 to 1980	1.3	1.2	1.2	1.3
1980 to 1985	1.4	1.2	1.2	1.3
1985 to 1990	1.3	1.2	1.2	1.2
1990 to 1995	1.0	0.9	1.2	1.2

Views of the Board

The rate of increase in population is predicted to slow from an average 1.7 percent over the historical period 1960 to 1974, to between 1.2 percent and 1.3 percent over the forecast period. The resultant population in 1995 is 29.2 million.

Economic Growth

Views of Submittors

The various views as to the expected Canadian rate of economic growth are summarized in Table III-2.

Gulf's GNP rates of growth assumed: modest growth in the economies of Canada's major trading partners, continued action against inflation through government guidelines and policies, no constraints on energy-related investments and no material supply shortages to hinder growth. Gulf expected real disposable income to grow at an average rate of 4.7 percent from 1975 to 1980, increase to an average of 5.4 percent per year over 1980 to 1985, and subsequently decline to 4.1 percent over 1990 to 1995. Industrial production was expected to grow at a declining average rate from 6.4 to 4.5 percent per annum during the period from 1975 to 1995.

Imperial predicted real GNP to grow at an average rate of 4.5 percent between 1975 to 1985 and a rate of 4 percent between 1985 and 1995. These rates of growth were indicated to vary between 3.5 to 5 percent through the forecast period.

Shell expected GNP to grow at a decreasing rate due to a decline in the rate of growth in the labour force and declining productivity.

Views of the Board

The Board's forecast employs a projection of economic growth based on the CANDIDE econometric model of the Canadian economy. The particular values chosen are similar to one of the economic growth cases used by Energy, Mines and Resources in its published paper "An Energy Strategy for Canada".

The forecast of economic activity used appears fairly optimistic for the period 1976 to 1980, with real gross national product increasing at an average annual rate of 5.2 percent. After 1980, however, economic growth is forecast to moderate, averaging 3.4 percent over the period 1980 to 1995. The Board views the resulting GNP growth rate of 3.8 percent between 1976 and 1995 as representing a medium economic growth scenario. This forecast of GNP growth rate is similar to Shell's forecast, although it is lower than those of Imperial, Gulf and Texaco in the later part of the forecast period.

Table III-2

REAL GROSS NATIONAL PRODUCT GROWTH RATES
Comparison of Forecasts
(Percent per annum)

	Gulf	Imperial	Shell	Sun	Texaco	NEB
1975 to 1980	5.0	4.5	5.2-5.5	4.5-6.0	4.7	5.4
1980 to 1985	4.8	4.5	3.9	4.5-6.0	4.4	4.3
1985 to 1995	4.2	4.0	3.1	—	4.2	3.0

Other features characterizing the projection of the economy used by the Board are summarized in Table III-3.

Prices

Views of Submittors

Gulf assumed domestic crude oil prices would reach world levels of $16 to $17 per barrel in 1980. Natural gas was expected to reach a Btu equivalent value in

Table III-3

DEMOGRAPHIC AND ECONOMIC GROWTH
NEB Forecast

	1975 Level	Percent per annum				1995 Level
		Historical	Forecast			
		1960-74	1976-80	1980-85	1985-95	
Gross National Product ($1961 billions)	79.0	5.3	5.2	4.3	3.0	170.4
Population (millions)	22.8	1.7	1.3	1.3	1.2	29.2
Households (millions)	6.9	2.9	2.7	2.4	1.9	10.7
Ratio of multiple* dwellings to total housing stock	0.421	0.418	0.439	0.458	0.486	0.486
Employment (millions)	9.3	3.1	3.0	2.3	1.6	13.7
Unemployment rate** percent	7.0	5.3	6.3	5.3	5.6	5.6
Proportion of employment* in commercial sector	0.564	0.549	0.583	0.615	0.677	0.677
Consumer price index* (1961 = 1)	1.849	1.669	2.625	3.517	5.910	5.910
Personal disposable income ($1961 billions)	55.8	5.1	4.1	3.6	2.7	107.0
Retail trade ($1961 billions)	27.8	4.8	3.7	2.5	2.0	46.8
Real domestic product in the industrial sector ($1961 billions)	26.5	5.5	5.6	4.5	3.0	60.3

* Annual level at period end shown, rather than growth rate.
** Period average shown, rather than growth rate.

Toronto at the same time. Electricity was expected to continue to cost relatively more than oil throughout the forecast period. Gulf provided price escalation factors which indicated that the average annual rate of growth in prices from 1980 to 1995 would be 2.6 percent, 3.2 percent and 4.9 percent for oil, gas and electricity respectively.

Imperial assumed that Canadian oil prices would reach world levels by 1980 and maintain world levels for the remainder of the forecast period. Crude oil prices were expected to escalate at least with future inflation. Natural gas was expected to reach Btu parity with crude oil by 1980 and achieve a premium value over Btu parity.

Shell assumed domestic crude prices would reach parity with imported crude by 1980, about $16 per barrel at Edmonton in current dollars escalating slightly less than 7 percent per year beyond 1980. In the post 1980 period, it was estimated that the average annual increase in the real price of crude oil would be between zero and two percent. With natural gas reaching Btu parity, the Toronto city-gate price was expected to be $2.35 per million Btu's by 1978. Electricity was assumed to face an increasing disadvantage in the major residential and commercial markets served by natural gas as a result of rates required to cover generating and capital costs. Sun Oil Company of Canada Ltd. ("Sun") expected domestic prices to reach world prices of $15 to $16 per barrel in 1980. No estimates were provided for subsequent years.

Texaco expected the domestic crude oil price to reach $15 in Edmonton by 1980 with a natural gas equivalence of $2.50 per thousand cubic feet ("Mcf"). No estimates were provided for the years beyond 1980.

Views of the Board

For the purposes of this forecast the Board assumes that the world price of crude oil will remain constant in real terms at its 1975 level. The domestic price of crude oil is assumed to rise towards the world price of oil, approaching it in 1980. With the other economic assumptions this implies a landed price of crude oil in Canada of approximately $17.00 per barrel in 1980 in nominal terms. The forecast assumes that the city-gate price of natural gas in Toronto will increase to parity with the price of crude oil at the refinery gate on a Btu equivalent basis in 1980. After 1980, oil and gas prices are assumed to remain constant in real terms. Electricity prices are assumed to increase in real terms to 1980, remaining constant in real terms thereafter.

The Board's assumed 1980 domestic crude oil price is in line with assumptions made by submittors and its assumption on the rise of domestic crude oil prices toward world prices, and the timing of parity for oil and gas prices are also consistent with postulates made by most submittors. Shell, however, assumed that parity of gas and oil would occur by the end of 1978. Comparison of assumptions made regarding the price of electricity is difficult, as little detail on these prices was provided by submittors.

It should be emphasized that these and other price assumptions are made strictly for forecasting purposes, and do not necessarily reflect government intentions in this area.

Interfuel Competition

Views of Submittors

Gulf expected that natural gas would face competition in the industrial sectors of Ontario and Quebec from heavy fuel oil until 1980. Beyond 1985, natural gas would penetrate further into Quebec as East Coast offshore supplies become available with the natural gas share of the Quebec market reaching 15 percent by 1995. In Alberta, developments in the petrochemical industry were expected to result in a growth in the market share held by natural gas. Natural gas service was not assumed to expand to Vancouver Island nor was expansion expected generally in thermal electric generation. Gulf anticipated that, in the light of recent history, incremental demand in the residential sector in the Atlantic Provinces and Quebec would go to electricity. The trend was expected to ease by 1979. Natural gas and electricity were expected to expand their shares at the expense of light fuel oil in Ontario, the Prairies and British Columbia.

Imperial's assessment of market shares in the combined residential/commercial sector is summarized in Table III-4 below. Expansion of the natural gas share in these combined sectors, after 1980, was assumed to be the result of expansion of market areas into Quebec City and Vancouver Island as supplies become available from the Beaufort Sea.

Table III-4

FUEL SHARES IN THE RESIDENTIAL/ COMMERCIAL SECTOR
Imperial Oil Limited Forecast
(Percent of Market)

	Oil	Natural Gas	Electricity
1975	49	32	19
1985	33	40	27
1995	24	42	34

For the industrial sector, Imperial expected that market shares would remain stable as the incentive to switch to natural gas disappeared. This incentive was assumed to be constrained prior to 1981 by supply. Short-falls in Southern Basin supply were assumed to be shared equally between industrial users and export customers. Coal was expected to take the new growth in electrical generation in Alberta and Saskatchewan but otherwise remain stable.

Shell assumed that natural gas would continue to have a competitive advantage and electricity an increasing disadvantage in the major residential and commercial markets served by natural gas. The use of heating oil in residential markets was expected to grow at a rate of 0.6 percent per annum until 1980. Electricity was expected to increase its share of the residential market, despite higher relative costs, because of the lower initial capital costs of electrical heating systems. In the commercial sector, energy demands were expected to be strong with natural gas and electricity increasing their penetration at the expense of oil. Natural gas was expected to increase its share of the industrial market, assuming frontier supplies were available. In Eastern Canada heavy fuel oil was expected to remain competitive with natural gas because of likely surpluses. No market area expansion was expected for gas in either British Columbia or Quebec. Important changes in the product mix were expected as growth in the transportation sector was assumed to be met by oil.

Texaco expected natural gas to be restricted in its use to petrochemical, residential and specialty industrial consumption as a result of increased concern for optimum consumption of this premium fuel. The relative price gap between alternative energy sources will narrow with electricity remaining the most expensive due to higher generating costs and the required rates of return. Coal and nuclear energy were expected to make inroads into petroleum demand in the latter ten years of the forecast period. Texaco assumed no extension of gas service in either Quebec or British Columbia.

The B.C. Energy Commission indicated in testimony that expansion of gas service to Vancouver Island remains an open question, but for forecasting purposes assumed no such extension.

Views of the Board

The market shares incorporated into the Board's forecast were developed on a judgmental basis by considering such factors as relative energy prices, relative capital costs of installation of heating equipment, and historical trends. It should be noted that no supply constraints are assumed on fuels which have been available historically in a given region. Moreover, for the purposes of the forecasts included in this report, it is assumed that no extension of the gas service area in the Province of Quebec or to Vancouver Island will occur during the forecast period. To the extent that there is an extension of the gas franchise area, the Board's forecast here overstates the demand for oil.

For Canada as a whole, the Board anticipates that oil will lose significant market shares in the residential and commercial sectors over the forecast period to natural gas and electricity. In the period before 1980, it is assumed that gas will be preferred to oil on

grounds of price. Electricity is assumed to be more attractive after 1980 than before as a result of the price assumptions discussed earlier in this chapter.

In the post 1980 period it is still assumed that natural gas will be preferred in the residential and commercial sectors. Btu equivalent prices at the Toronto city-gate imply that the cost of gas to consumers in Northern Ontario and the Prairies will remain lower than that of oil. In the residential sector this preference for natural gas is reinforced by its higher burning efficiency compared to light fuel oil. The oil share of the residential sector declines from 51.7 percent in 1974 to 34.5 percent in 1995. In the commercial sector it is forecast to decline from 33.7 percent in 1974 to 21.8 percent in 1995. In terms of the combined residential/commercial market, the oil share declines from 44.6 percent in 1974 to 28.1 percent in 1995.

In the industrial sector, the oil market share remains relatively constant at approximately 30 percent over the forecast period. Electricity's share of the industrial market is also expected to remain fairly constant, while the natural gas share is assumed to increase slightly. Market share behaviour varies significantly between regions, reflecting differences in market situations, expected relative prices, and the availability of substitutes.

It is difficult to make direct comparisons of the Board's estimated market shares with those of the submittors, since the definitions of the residential, commercial and industrial sectors are not consistent. Allowing for this factor, however, it becomes apparent that in the residential and commercial sectors, the behaviour of the Canada-wide oil share assumed by the Board is similar to that of Gulf and Shell, while Imperial indicates a more pronounced decline in the oil share of this market. In the industrial sector, both Gulf and Shell assumed a declining market share for oil, while Imperial's oil share remains relatively constant, as does the Board's. Significant regional variations exist for each sector, partly as a result of the varying assumptions made with regard to extension of the natural gas service area.

FORECAST OF ENERGY DEMAND

This section presents the results obtained by submittors and by the Board for primary energy demand, and for secondary energy demand by sector.

Primary energy is the quantity of energy as it is produced in the form of crude oil, natural gas, coal, etc. regardless of how that energy is used. Secondary energy is the energy as it is received by the consumer, that is, the energy content of fuels that go into the furnace, the automobile or other end uses. For most purposes, the details of measurement of primary and secondary energy are less important than understanding that primary energy is always larger than secondary. One of the main differences arises from the fact that, using fossil fuels, roughly three units of primary energy are necessary to generate one unit of secondary energy in the form of electricity.

Electricity derived from hydro or nuclear energy sources presents special problems when considering the concept of primary energy demand. For the purposes of its study of trends in primary energy demand, the Board has included a hypothetical component in primary energy demand to correspond to the historic and anticipated use of hydro and nuclear generated electricity. To calculate this hypothetical component the Board assumes that electricity generated using hydro and nuclear energy is derived instead from fossil fuels and requires a heat input of 10,000 Btu's per kilowatt hour. This assumption facilitates the study of long-term trends in primary energy demand by freeing the analysis from the influences of historic or forecast trends in electrical generating patterns insofar as these relate to the split between nuclear and hydro generating facilities and thermal-fired plants.

Of the submittors, Imperial and Texaco provided their figures on a primary energy demand basis making a hypothetical adjustment for nuclear and hydro generation similar to that used by the Board. The Board has adjusted the Gulf figures so that they could be included on a comparable basis in Table

III-5. The Shell data did not provide sufficient information to permit such an adjustment and accordingly are not strictly comparable with the other data shown.

Primary Energy Demand

Views of Submittors

The following table provides comparative growth rates for forecasts of Canadian primary energy demand:

Table III-5

PRIMARY ENERGY DEMAND — GROWTH RATES
Comparison of Forecasts
(Percent per annum)

		Oil	Total Energy
Gulf	1975-1985	2.7	4.3
	1985-1995	1.2	2.6
Imperial	1975-1985	3.1	4.6
	1985-1995	2.0	3.6
Shell*	1974-1985	2.3	3.3
	1985-1995	1.4	2.0
Texaco	1975-1985	3.7	4.8
	1985-1995	2.7	5.0
NEB	1975-1985	2.9	3.3
	1985-1995	1.6	2.6

* Rate of growth in energy demand by end-use, excludes some sectors so Shell data are not comparable with other submissions.

Gulf, Imperial and Texaco provided complete information on Canadian primary energy demand. Their estimates of the primary demand for oil ranged from 4.7 to 5.0 quadrillion Btu's ("quads") by 1985. Total primary energy demand for 1985 was estimated between 12.2 to 13.0 quads. By 1995, the range of estimates was 5.3 to 6.5 quads for oil and 15.8 to 21.1 quads for total energy.

Shell did not provide direct information on primary energy demand. It did, however, provide information on energy demand by end-use sector for all major demand components. Two principal components of primary energy demand not included in its information were the estimated uses and losses in the energy supply sector and the losses in converting from primary to secondary forms of energy. Shell's estimates of total end-use demand in the sectors considered were 7.1 and 8.7 quads for 1985 and 1995 respectively.

Views of the Board

Primary energy demand is forecast to increase from a 1975 level of 8.0 quads to 11.0 quads in 1985 and to 14.3 quads in 1995. This implies an average annual rate of growth of 2.8 percent over the forecast period. The Board's estimate is lower than that of Gulf, Imperial and Texaco, as a result of, among other factors, lower economic growth assumptions over the later part of the forecast period.

Primary oil demand is forecast by the Board to increase more slowly than primary energy demand rising from a 1975 level of 3.5 quads to 4.7 quads in 1985 and 5.5 quads in 1995 for a growth rate averaging 2.1 percent over the forecast period. The share of total energy demand provided for by oil products is forecast to decline from 44.3 percent in 1975, to 38.4 percent in 1995. The Board's estimate of primary oil demand is lower than that of Imperial and Texaco but higher than Gulf's estimate.

Energy Demand by Sector

Views of Submittors

Gulf, Imperial and Shell provided information on energy demands by sector. The relevant growth rates are summarized in Table III-6.

Table III-6

ENERGY DEMAND-GROWTH RATES BY SECTOR*
Comparison of Forecasts
(Percent per annum)

	1975 to 1985				1985 to 1995			
	Gulf	Imperial	Shell**	NEB	Gulf	Imperial	Shell	NEB
Residential	2.4	—	1.9	1.1	2.4	—	1.0	1.6
Commercial	5.2	—	3.9	3.3	3.8	—	2.7	3.4
Residential & Commercial	3.6	3.3	3.1	2.0	3.1	3.0	1.8	2.5
Industrial	4.8	5.1	3.8	3.2	3.2	3.7	2.7	3.5
Transportation	1.5	3.5	1.8	2.6	0.6	1.9	1.3	0.7

* Definitional differences exist in the various sectors.
** 1974 to 1985.

In the residential sector Gulf predicted steady growth throughout the forecast period. Shell predicted higher average annual growth rates in the period before 1985 than during the period 1985 to 1995. These conclusions reflect a number of factors including the demographic structure of the population and the number, types and sizes of future households. For the commercial sector both Gulf and Shell expected energy demand to grow faster than for the other sectors. Imperial did not provide a breakdown of its combined residential and commercial sector. In the combined residential and commercial sectors, however, Imperial predicted slightly lower growth in the later half of the forecast period. In the combined residential and commercial sectors, Gulf predicted higher average annual growth than did Imperial and Shell in each half of the forecast period. Shell showed the lowest demand growth rate in both periods.

For industrial demand higher growth rates were predicted by Gulf, Imperial and Shell than for either the combined residential and commercial sectors or the transportation sector throughout the forecast period. Gulf predicted stronger demand in the commercial sector than in the industrial sector and expected the margin in these growth rates to widen over the forecast period. Shell predicted nearly the same rate of growth in the commercial and industrial sectors over the forecast period.

In the transportation sector, the rate of growth was predicted by the submittors to decline steadily. Of the three submittors, Imperial predicted the highest growth in this sector.

Views of the Board

The Board's forecast of energy demand growth rates by sector is also shown in Table III-6. The resulting forecasts of total secondary energy demand are tabulated in Appendix H along with the corresponding estimates of total oil demand.

Energy Demand in the Residential, Commercial and Industrial Sectors

The Board's forecast of energy demand for the residential, commercial and industrial sectors is summarized in Figure III-1.

Under the Board's price assumptions growth in total residential sector energy demand is reduced to an annual average of 1.4 percent over the period 1976 to 1995. In this sector, energy demand is forecast to grow at its slowest rate over the 1980 to 1985 period, reflecting both the rapid increase in energy prices during the 1976 to 1980 period and the delayed response by consumers to price increases. Most of the response to a price increase is assumed to occur in the three years after the initial price increase, because of delays by consumers in the purchase, for example, of insulation or more efficient energy appliances. With regard to the influe.. on residential demand of revisions of building codes during the forecast period, it is felt that such codes, to the extent they are adopted, will ensure that new houses will be constructed to an energy standard which will be economic for the home owner. Hence, it is appropriate to measure the impact on demand of this factor through a price response mechanism.

Oil demand in the residential sector is forecast to decline slowly at a rate of 0.5 percent per year over the period 1976 to 1995. This results from the slow growth in overall energy demand in this sector, and the declining market share for oil (see the discussion earlier in this Chapter under the heading of Interfuel Competition).

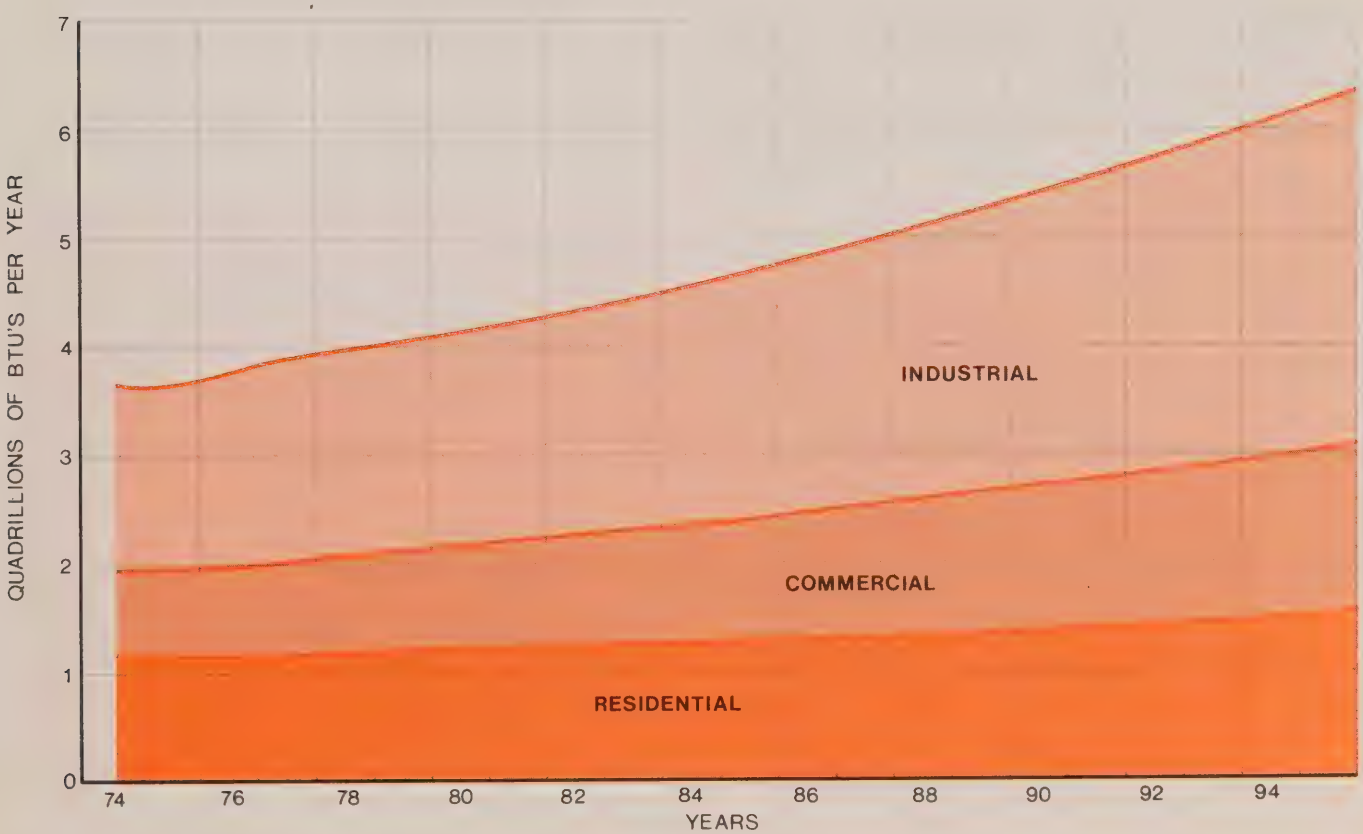


Figure III-1. **ENERGY DEMAND IN THE RESIDENTIAL, COMMERCIAL AND INDUSTRIAL SECTORS NEB Forecast**

In the commercial sector it is assumed that higher energy prices will reduce the average annual rate of growth in energy demand to 3.3 percent over the period 1976 to 1995. This expected response to higher prices is less in percentage terms than in the residential sector because consumers living in apartment buildings or other forms of multiple housing frequently do not face energy costs directly, and thus have only an indirect incentive to conserve. Oil demand in the commercial sector is forecast to increase less rapidly than total energy demand.

In the industrial sector total energy demand is assumed to grow at an average annual rate of 2.5 percent between 1976 and 1980, increasing to 3.1 percent between 1980 and 1985, and 3.5 percent between 1985 and 1995, to yield an average annual growth rate of 3.2 percent over the entire period. This slower rate of growth in energy demand in the earlier years of this scenario reflects the effect of increases in the real price of energy up to 1980. This rate compares to an average annual growth in demand of 5.3 percent between 1958 and 1974. The oil product market share of the industrial sector remains relatively constant at approximately 30 percent over the forecast period. The average annual growth rate in demand for oil is 3.3 percent between 1976 and 1995.

Energy Demand in the Transportation Sector

The Board's forecast of energy demand for the transportation sector is summarized in Figure III-2. This sector has been subdivided to consider road, rail, air and marine transportation separately. The results for each of these segments are discussed below.

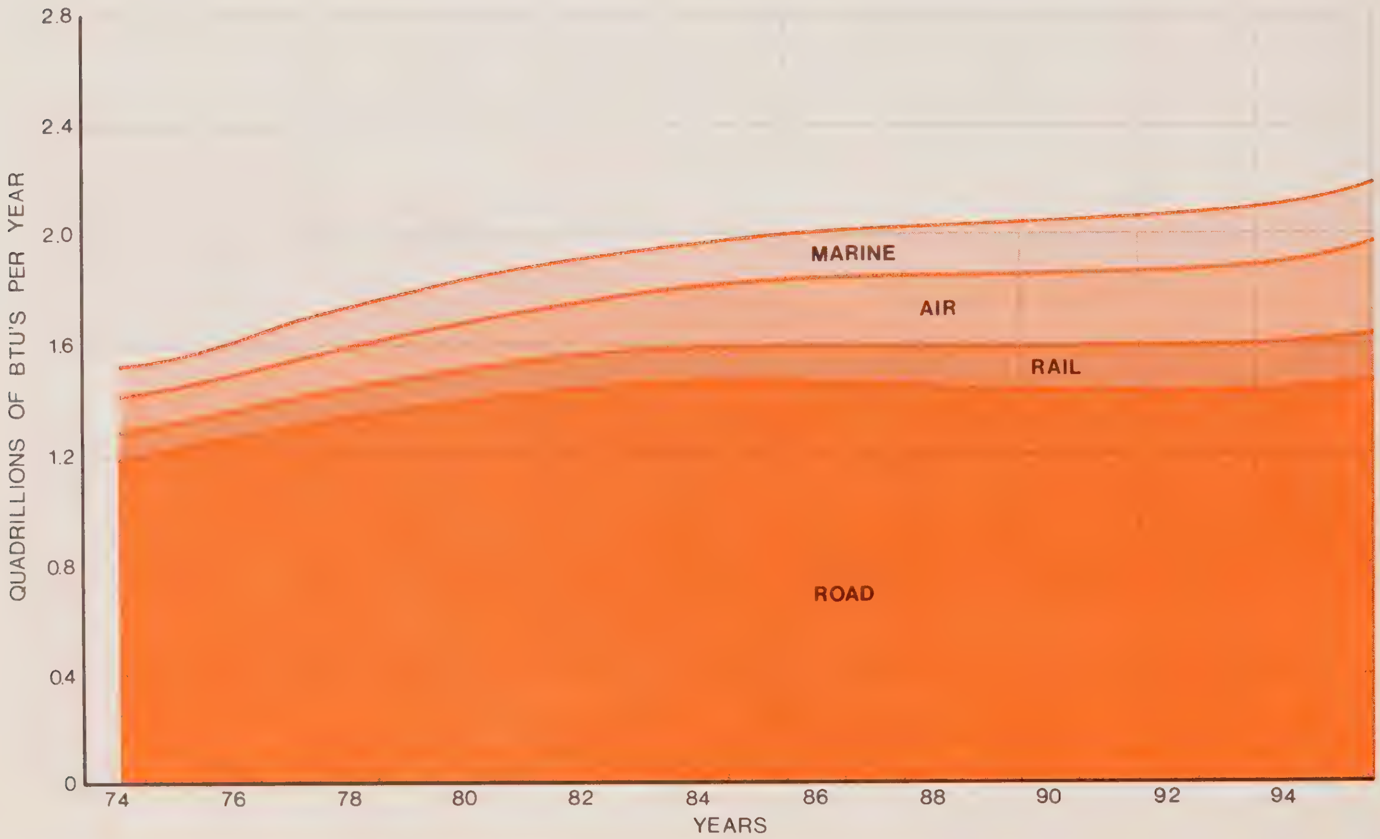


Figure III-2. **ENERGY DEMAND IN THE TRANSPORTATION SECTOR**
NEB Forecast

In 1974, road transportation consumption of energy was 1.172 quads of which 92.8 percent was motor gasoline. This consumption of motor gasoline increased at an average annual rate of 5.4 percent during the period 1966 to 1974. Growth in the demand for motor gasoline is forecast to be significantly lower than the historical rate of growth as a result of the substantial increase in fuel economies assumed, and the forecast shift in consumer preference towards smaller and lighter cars.

The scope for improving the fuel economy of diesel trucks appears rather limited. Also, while the possibility of intermodal shifts from road to rail cannot be ruled out, a large-scale conversion seems unlikely. Therefore, road consumption of diesel fuel oil is forecast to increase at an average annual rate of 6.9 percent during 1976 to 1985 and at 3.4 percent during 1985 to 1995. As a result of the high rates of growth forecast for diesel fuel oil relative to those forecast for motor gasoline, the share of diesel fuel oil in the road consumption of energy is estimated to increase from 7.2 percent in 1974 to 11.2 in 1985 and to 15.8 percent in 1995.

Total energy demand (motor gasoline plus diesel fuel oil) in the road transportation sector is estimated to increase from 1.246 quads in 1976 to 1.454 quads in 1985, at an average annual rate of 1.7 percent, but it is forecast to decline to 1.425 quads between 1985 and 1990. After 1990, however, demand is estimated to increase again at an average annual rate of 0.25 percent per year to 1.443 quads in 1995, as a result of increases in diesel fuel consumption. The factors giving rise to these overall trends are discussed in Chapter IV.

The total demand for energy for rail transportation is projected to increase at an average annual rate of 2.7 percent from 1976 to 1995. The demand for diesel fuel, the sole source of motive power in this sector, is forecast to rise at an average annual rate of 2.8 percent during the 20-year period 1976 to 1995. The average annual rate of increase of diesel fuel demand declines from 3.4 percent for the period 1976 to 1980 to 2.4 percent for the period 1985 to 1995. The average rate of growth is lower than the average annual rate of 3.5 percent experienced during the historical period 1958 to 1974. Conservation due to rising fuel prices is assumed to have minimal effect on demand for fuel in the rail sector because significant improvements are not foreseen in engine efficiencies and extensive electrification is not considered likely.

Aviation turbo fuel constitutes approximately 95 percent of total energy demand for air transportation. Over the periods 1976 to 1980, 1980 to 1985 and 1985 to 1995 aviation turbo fuel demand is forecast to increase by 5.9 percent, 5.7 percent and 3.5 percent per year respectively. For aviation gasoline, demand is forecast to increase by 2.7 percent per year over the 1976 to 1980 period, remain constant from 1980 to 1985, and increase at an average rate of 3.4 percent per year over the 1985 to 1995 period. The market decline in the growth in aviation gasoline demand relative to turbo fuel during the first half of the forecast period reflects the expected continued replacement of piston-type aircraft by turbo aircraft. After 1985, it is forecast that such replacement effects will be minimal.

Total energy demand for marine transportation is projected to rise at average annual rates of 7.9 percent from 1976 to 1980, 2.7 percent from 1980 to 1985, and 2.0 percent from 1985 to 1995. This slowing down in the rate of growth reflects the similar trend expected in economic growth. The two principal oil products used in the marine transportation sector are diesel fuel and heavy fuel oil. In the 1976 to 1980 period, demand for heavy fuel oil is expected to increase fairly rapidly, particularly in Quebec and the Atlantic regions. After 1980, however, the rate of increase in diesel fuel demand is expected to be higher than the corresponding rate for heavy fuel oil, as the use of engines requiring diesel fuel becomes more widespread. For the marine sector, no provision has been made for reductions in energy demand stemming from conservation measures.

ENERGY CONSERVATION AND THE EXPORT FORMULA

As outlined in its reports of October 1974 and September 1975 and discussed again elsewhere in this report the Board has adopted an export formula to determine the crude oil export levels which are appropriate given the goal of providing protection for Canadian requirements. To ensure that Canadian consumers receive the benefits from oil conservation programs and from their voluntary reductions in oil use resulting from increased prices, the formula requires that estimates be made of the quantitative impact of conservation. The annual savings resulting from these programs are taken into account when calculating allowable exports. In this way the benefits of conservation will be retained for Canadian consumers and will not flow through in the form of increased exports.

It will be recalled that the earlier parts of this chapter are concerned with estimating the most likely demand. By definition, those forecasts indicate energy demand after taking into account reductions in demand resulting from price increases after 1972 and various existing and expected conservation programs. It follows that for the purposes of the export formula it is necessary to estimate the levels which energy demand would reach had prices remained at 1972 levels and these conservation programs not been adopted. The Board's estimate of demand under this non-conservation assumption is identified here and elsewhere in this report as the Export Formula Case.

In the hearing order, submittors were invited to indicate the extent to which their forecasts of demand reflect the effects of conservation. The views expressed by the submittors in response to this invitation are outlined in the following paragraphs. Thereafter consideration is given to the Board's Export Formula Case.

Views of Submittors

In the residential and commercial sectors, Gulf expected energy savings from conservation to increase from 10 percent of its non-conservation demand estimate in 1980 to 20 percent in 1995. These savings were attributed to a number of factors including improved insulation standards, re-insulation of up to 75 percent of homes by 1985, federal government expenditure cut-backs in the order of 10 percent and the design of more energy-efficient buildings.

In the industrial sector, Gulf attributed conservation effects mainly to higher prices. Energy savings as a percentage of the non-conservation case were estimated to increase from 9 percent in 1980 to 21 percent in 1995. These savings were attributed to various efforts including waste heat recovery, increased use of waste materials as fuel and process redesign. The transportation sector savings were attributed to federal and provincial government initiatives, guidelines, taxes and improved fuel economy standards. Expressed as a percentage of the non-conservation case the potential savings of motor gasoline in 1995 were estimated to be 45 percent.

Imperial anticipated that the conservation response in the combined residential and commercial sectors would be slightly stronger than the moderate response expected in its 1975 submission, where reductions in the order of 10 percent by 1990 had been anticipated. This estimate was increased to 13 to 14 percent because certain conservation actions have now been implemented. In the transportation sector, again referring to its 1975 submission, Imperial indicated that compared to the savings in 1990 of 15 percent in its most likely scenario (i.e., the moderate case) an increased conservation response was now expected as a result, for instance, of automobile mileage standards having been enunciated. Imperial assumed that most of the response would be price-driven.

Shell supplemented its forecast of demand by providing product demand estimates assuming a business as usual or non-conservation case. In this scenario, residential demand reflected constant energy consumption by household at levels prior to 1974 with no allowance for savings through increased insulation and more efficient heating equipment. Shell indicated that prices were the most significant conservation incentive but legislation was important in those areas where the fuel buyer does not directly influence the conservation measure, for example, the insulation of new housing.

In the commercial sector, Shell's non-conservation demand estimate was forecast solely by using the relationship with commercial employment without reductions included in the primary forecasts. Similarly, the industrial demand was based only on GNP expectations in the non-conservation case. Shell assumed in the transportation sector of its non-conservation scenario, an improvement of 40 percent in the sales-weighted fuel efficiency of automobiles by 1980 vs the average fuel efficiency in 1974 and attributed this to the effects of the Canada – U.S. auto pact. In this scenario, Shell assumed no Canadian government guidelines on automobile efficiencies.

In determining the effect on crude oil demand of conservation measures and changes in price, Texaco made a subjective analysis. Historical trends were analyzed and modified in view of economic forecasts and conservation trends.

Texaco expressed the view that prices are not a particularly effective tool for achieving energy conservation although it referred to an independent econometric study which indicated that a doubling of the real price of crude oil would reduce oil demand by about 16 percent by the year 1980.

Texaco outlined three scenarios, each of which incorporated conservation measures taken to date and the assumption that oil prices in Canada would reach world levels by 1980. The three cases may be described as follows:

- continuation of existing legislative and similar restraints upon demand,
- extreme conservation restraints, and
- "most-likely" conservation case.

The first case assumed that no new conservation measures would be instituted over those presently in force. In the extreme case it was assumed that additional conservation measures would be put in place to the extent possible, but without significantly reducing the Canadian standard of living. More specifically this extreme conservation case assumes very extensive legislation concerning insulation standards in buildings, highway vehicle sizes, highway speed limits and the enforcement of such legislation.

Texaco's most-likely case assumed some further conservation legislation such as building code modifications but to a lesser degree than in the extreme conservation case. Overall, Texaco was of the opinion that although demand for petroleum products will lessen as a result of price increases, the effects from legislated conservation could be greater than from price increases.

Views of the Board

In developing its forecast of energy demand the basic approach taken by the Board towards conservation is to assume that, with the exception of the road transportation sector, all conservation of energy will arise in response to price changes. A brief discussion of the estimated elasticities of energy demand with respect to price changes appears in Chapter VIII. In the road transportation sector conservation is assumed to occur both as a result of price increases and as a result of legislation designed to reduce energy consumption.

For its Export Formula Case, i.e., in determining what energy demand might have been without the conservation efforts that are expected, the Board adopted the same economic assumptions as in its forecast, with the exception of those relating to energy prices. It will be recalled that in its forecast the Board assumes that the world price of crude oil will remain constant in real terms at its 1975 level. For its Export Formula Case, the Board assumes instead that energy prices will remain constant in real terms at the levels which prevailed at the end of 1972. Market shares are assumed to be the same as in the Board's forecast. As stated in previous Board reports, it is felt that decreases in the demand for refined petroleum products arising from the substitution of other forms of energy cannot be classified as conservation.

Conservation in the residential sector, as measured by the decrease in energy demand between the Export Formula Case and the Board's forecast is estimated to be 8.1 percent in 1980, 13.0 percent in 1985, and

remaining relatively constant thereafter. The percentage savings in oil products resulting from consumer response to price increases are similar to those arising for total energy: 8.4 percent in 1980, and 13.2 percent in 1985, using the Export Formula Case as the bench mark.

In the Export Formula Case the commercial energy demand is forecast to continue to increase fairly rapidly. Conservation as measured by the decrease in energy demand between this case and the Board's forecast is estimated at 8.5 percent in 1980, and 12.3 percent in 1985. The corresponding figures for the conservation of oil products in the commercial sector are estimated at 10.1 percent in 1980 and 14.4 percent in 1985.

For the industrial sector, the percentage differences in energy demand using the Export Formula Case as a base grows from 2.5 percent in 1976 to 12.1 percent in 1980 and to approximately 19 percent in 1985 and thereafter. Using the same base the effect of conservation on oil product demand rises from 2.9 percent in 1976 to 19.5 percent in 1985 reaching 20.0 percent in 1995.

Turning to the transportation sector, for road transportation the low energy prices of the Export Formula Case combined with small increases in assumed fuel economies of gasoline-using vehicles result in significantly higher rates of growth in total energy requirements. The effect of conservation on motor gasoline demand is to reduce the Board's forecast demand as compared to the Export Formula Case by 13.9 percent in 1980, 29.4 percent in 1985, and 42.1 percent in 1995. For rail transportation conservation is assumed to have minimal effect on demand. For air transportation it is assumed that reduction in energy use by airlines as a result of higher oil product prices will lead to annual savings, compared to the Export Formula Case which will increase from 0.5 percent in 1975 to 3.3 percent in 1995. For marine transportation no reduction in energy demand stemming from conservation measures has been assumed.

For the Export Formula Case, further details on the demand for energy and oil products by sector of consumption are provided on page 3 of Appendix H. Appendix I includes the corresponding total demand for refined petroleum products for Canada as a whole and by region. To facilitate comparison with the NEB's forecast, the demands for individual refined petroleum products in this Export Formula Case are included in the graphs in Chapter IV (Figures IV-1 to IV-7).

Demand for Refined Petroleum Products

This chapter is concerned with outlining the main considerations involved in translating the forecasts of energy and oil demand by sector of consumption into forecasts of demand for individual categories of refined petroleum products.

OVERVIEW OF TOTAL REFINED PETROLEUM PRODUCT DEMAND

Views of Submittors

The views of the submittors reflected expectations of lower rates of growth in petroleum product demand in the future. Factors cited which contributed to the declining growth rate forecasts were:

- lower rates of growth in population,
- lower rates of growth in the labour force,
- lower productivity,
- the effects of conservation policies,
- higher prices for oil and other energy forms, and
- a shift toward nuclear generated electrical energy.

As shown in Table IV – 1, Gulf, Imperial, Shell and Texaco predicted that the average annual rate of growth of total refined product sales in Canada will range between 3.9 and 4.2 percent from 1976 to 1980. These rates of growth reflect a decline from the historic rate of 5.2 percent in the early 1970's cited by Texaco. From 1980 to 1995, lower average annual growth rates ranging from 1.3 to 2.6 percent were expected.

Table IV-1

REFINED PETROLEUM PRODUCTS SALES GROWTH RATES
Comparison of Forecasts

	Gulf	Imperial	Shell	Texaco	NEB
1976-1980	4.1	3.9	4.2	3.9	3.8
1980-1995	1.3	2.3	1.3	2.6	1.6

Submitted forecasts of sales of refined petroleum products by fuel type varied considerably as indicated by the summary presented in Table IV – 2. Over the forecast period Gulf and Shell predicted lower growth than did Imperial and Texaco. The divergence of views was most evident in motor gasoline where Gulf and Shell predicted a small decline in the absolute level of sales beyond 1980 while Imperial and Texaco expected low growth.

The submittors' estimates of total refined petroleum product demand ranged from 1,932 Mb/d to 1,994 Mb/d in 1980 and from 2,338 Mb/d to 2,906 Mb/d in 1995. The various factors cited as affecting the rate of growth in demand were not expected to have the same impact on each product. A shift in product mix was indicated from gasoline to middle distillates.

For light fuel oil, kerosene, and stove oil, Gulf, Imperial and Shell predicted minimal or no growth beyond 1980. Texaco predicted comparatively strong growth for these products.

For diesel fuel, there was agreement among all four companies that demand would continue to grow but at declining annual rates.

For heavy fuel oil, Imperial and Shell had similar predictions of growth patterns. Gulf's prediction was less optimistic throughout the forecast period. Texaco was the least optimistic in the early part of the forecast and the most optimistic in the latter part of the forecast.

Agreement seemed to exist among the major marketing companies as to the likely pattern of change in the proportionate demand for petroleum products. All four predicted declining proportionate demand for both motor gasoline and light fuel oil, kerosene and stove oil. Diesel fuel was expected to increase its proportionate share of demand.

The graphs in a later part of this chapter show that, for the individual petroleum products, the submittors made widely different demand forecasts and none of their estimates was consistently the highest or the lowest for all products. Imperial and Texaco show considerably higher motor gasoline demand than Gulf

Table IV-2

REFINED PETROLEUM PRODUCTS NET SALES*

Comparison of Forecasts

(Thousands of Barrels Per Day)

		Gulf			Imperial			Shell		
		Net Sales	AAGR %	Percentage of Total Sales	Net Sales	AAGR %	Percentage of Total Sales	Net Sales	AAGR %	Percentage of Total Sales
Motor Gasoline										
	1976	611	—	37.1	612	—	36.8	611	—	36.1
	1980	655	1.8	33.9	695	3.2	35.8	646	1.4	32.4
	1985	633	-0.7	30.5	791	2.6	35.4	592	-1.7	28.1
	1995	594	-0.7	25.4	875	1.0	31.9	556	-0.7	22.8
Light Fuel Oil, Kerosene and Stove Oil										
	1976	324	—	19.7	314	—	18.9	336	—	19.8
	1980	335	0.8	17.3	309	-0.4	15.9	353	1.2	17.7
	1985	348	0.8	16.8	314	0.3	14.0	349	-0.2	16.6
	1995	364	0.5	15.6	314	0.0	11.4	350	0.0	14.4
Diesel Fuel Oil										
	1976	195	—	11.8	196	—	11.8	199	—	11.7
	1980	239	5.2	12.4	241	5.3	12.4	251	6.0	12.6
	1985	299	4.6	14.4	294	4.1	13.1	299	3.6	14.2
	1995	427	3.6	18.3	425	3.8	15.5	398	2.9	16.3
Heavy Fuel Oil										
	1976	303	—	18.4	303	—	18.2	312	—	18.4
	1980	369	5.1	19.1	382	6.0	19.7	391	5.8	19.6
	1985	408	2.0	19.7	426	2.2	19.1	419	1.4	19.9
	1995	468	1.4	20.0	509	1.8	18.5	501	1.8	20.6
Total Refined Products**										
	1976	1647	—		1665	—		1694	—	
	1980	1932	4.1		1943	3.9		1994	4.2	
	1985	2074	1.4		2236	2.8		2106	1.1	
	1995	2338	1.2		2744	2.1		2437	1.5	

AAGR = Average Annual Growth Rate

* Net Sales are defined as total market sales adjusted for industry use and loss, exports and imports.

** Includes all other products, not shown elsewhere in this table.

Table IV-2 (continued)

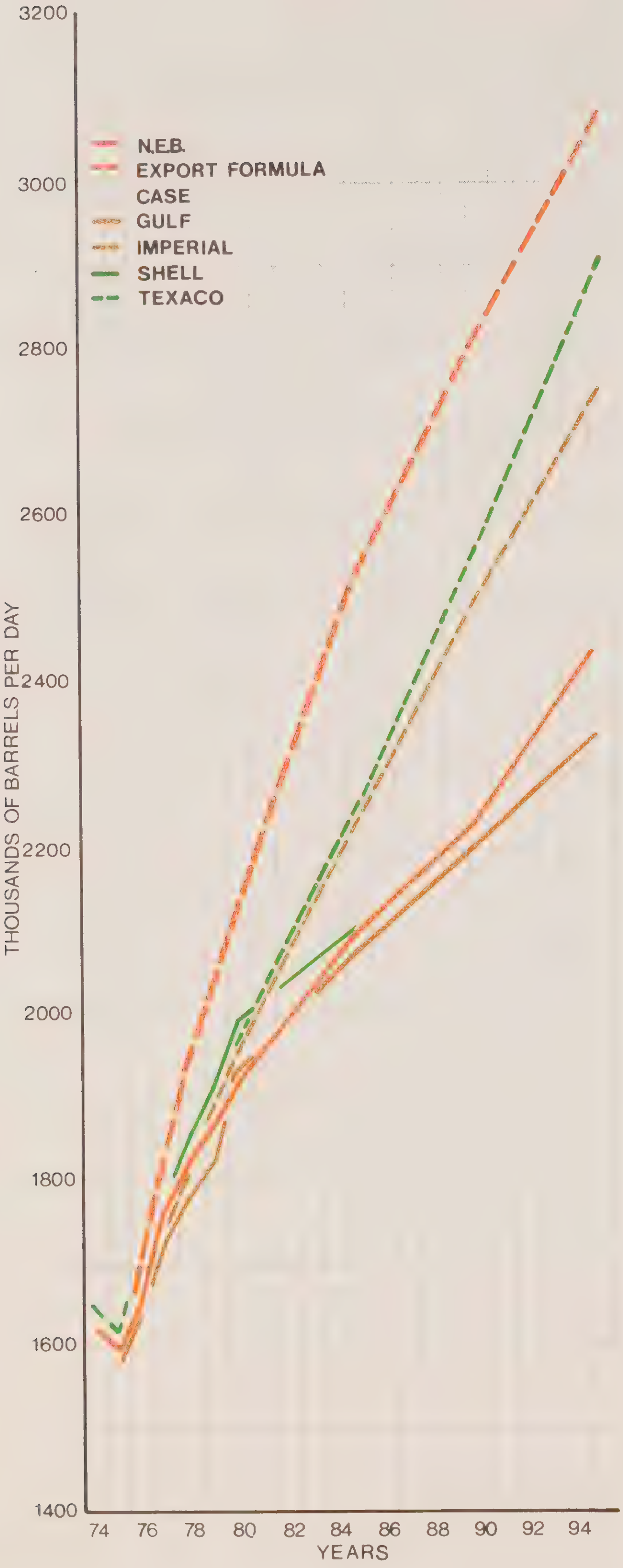
		Texaco			N.E.B. Forecast		
		Net Sales	AAGR %	Percentage of Total Sales	Net Sales	AAGR %	Percentage of Total Sales
Motor Gasoline							
	1976	609	—	36.1	606.6	—	36.6
	1980	669	2.4	34.1	664.2	2.3	34.6
	1985	731	1.8	32.4	677.4	0.4	32.3
	1995	859	1.6	29.6	637.5	-0.6	26.2
Light Fuel Oil, Kerosene and Stove Oil							
	1976	336	—	19.9	327.7	—	19.8
	1980	387	3.6	19.7	329.1	0.1	17.1
	1985	435	2.4	19.3	334.3	0.3	15.9
	1995	544	2.3	18.7	360.2	0.7	14.8
Diesel Fuel Oil							
	1976	195	—	11.6	199.9	—	12.1
	1980	232	4.4	11.8	234.6	4.1	12.2
	1985	279	3.8	12.4	278.4	3.5	13.3
	1995	383	3.2	13.2	374.6	3.0	15.4
Heavy Fuel Oil							
	1976	291	—	17.3	297.0	—	17.9
	1980	357	5.2	18.2	362.6	5.1	18.9
	1985	416	3.1	18.4	424.6	3.2	20.2
	1995	553	2.9	19.0	486.8	1.4	20.0
Total Refined Products**							
	1976	1685	—		1657.8	—	
	1980	1964	3.9		1922.1	3.8	
	1985	2256	2.8		2098.7	1.8	
	1995	2906	2.6		2431.2	1.5	

AAGR = Average Annual Growth Rate
* Net Sales are defined as total market sales adjusted for industry use and loss, exports and imports.
** Includes all other products, not shown elsewhere in this table.

or Shell and this partially accounts for their having higher overall total product demand.

Views of the Board

The Board's forecast of total refined petroleum product demand in Canada indicates an increase from



an actual level of 1,658 Mb/d in 1976 to 2,431 Mb/d in 1995. The Board's forecast is compared to submittors' forecasts in Table IV – 2 and Figure IV – 1. The Board's forecast demand for the major categories of refined petroleum products is also shown in Appendix H by sector of consumption for total Canada. In Appendix I, a regional breakdown of this forecast demand is presented by product category.

The Board expects product demand in Canada to increase at 2.0 percent per annum over the next two decades. Growth is forecast to slow during the period from 3.8 percent per year from 1976 to 1980 to 1.6 percent per year thereafter. The slackening results from increasing energy prices and lower growth in both the economy and the population.

Growth in the demand for total refined petroleum products is expected to average 2.2 percent per year WOV over the forecast period, and 1.8 per cent per year EOV. Details of this subdivision of demand are presented in Appendix I.

Slowing in the demand for motor gasoline as a result of expected consumer preference for smaller cars, major improvements in fuel economies, and consumer response to gasoline price increases, contributes most significantly to the decline in the rate of increase in total product demand. This leads to a shift in the percentage composition of total product demand. Motor gasoline and light fuel oil, kerosene and stove oil are expected to decline as a proportion of total product demand.

Figure IV-1. **DEMAND FOR REFINED PETROLEUM PRODUCTS**
Comparison of Forecasts

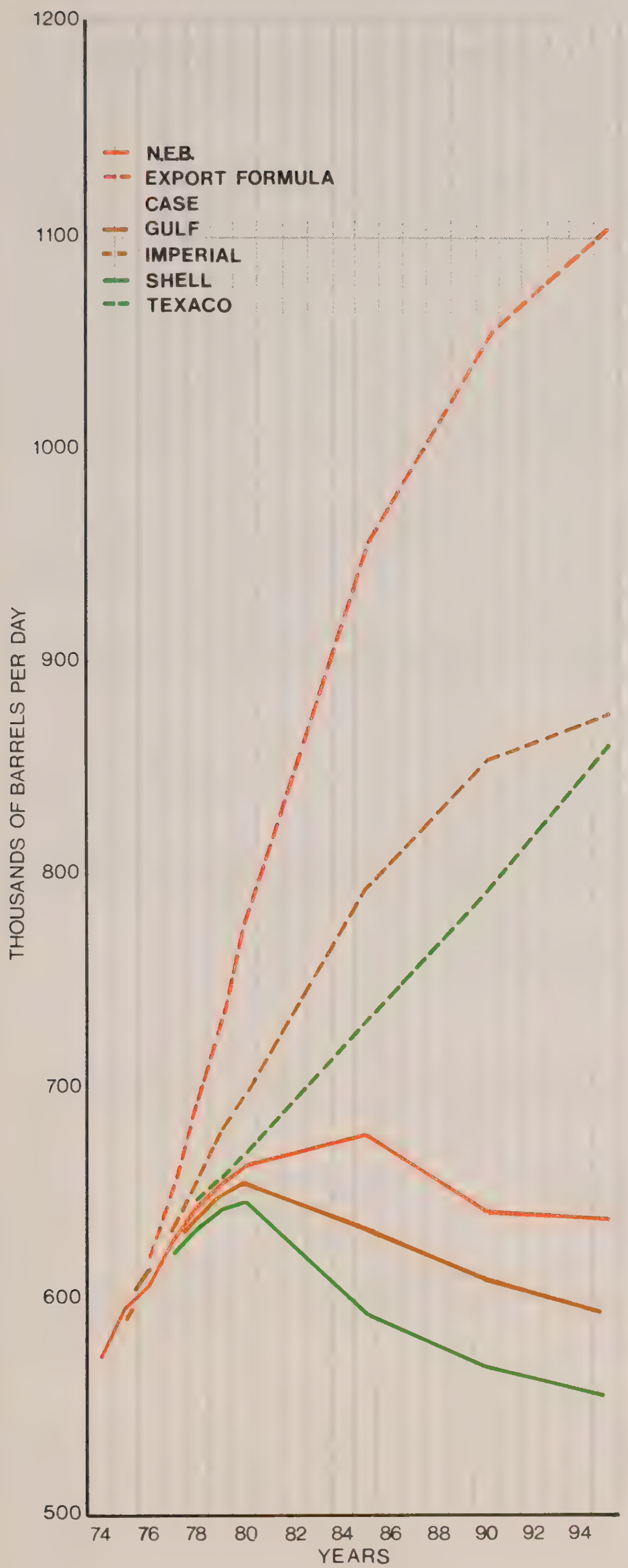


Figure IV-2. **DEMAND FOR MOTOR GASOLINE**
Comparison of Forecasts

MOTOR GASOLINE

Views of Submittors

The submittors' most likely forecasts of demand for motor gasoline in Canada are compared graphically in Figure IV – 2.

Gulf expected motor gasoline consumption to increase slightly from current levels of 611 Mb/d in 1976 to a peak of 655 Mb/d in 1980, and then to decline by 1995 to levels existing in 1975 of 596 Mb/d. These estimates were derived from assumptions regarding the number of vehicles, their usage and especially their fuel economies. Average miles per gallon were expected to increase from 17.5 mpg in 1975 to 30.0 mpg in 1995.

Imperial expected motor gasoline demand to decline in the automobile segment of the market, as mileage standards are adopted of 24 and 33 mpg in 1980 and 1985 respectively. The whole fleet mix was assumed to be such that cars would average 25 mpg in 1985. The non-automobile segment of motor gasoline demand, however, was expected to continue to grow at an average rate of 4 to 5 percent per year which contributed to Imperial's comparatively high forecast of demand. As a result, motor gasoline demand was expected to continue to grow throughout the forecast period to 695 Mb/d in 1980 and 875 Mb/d in 1995.

Shell predicted a change in the demand for products toward middle distillate products and away from motor gasoline as a result of improved efficiency, smaller vehicles and lower vehicle utilization. Gasoline demand was thus expected to increase at 2 percent per annum until 1980 and to decline to well below current levels to 556 Mb/d in 1995. Shell assumed refineries would operate at a level necessary to meet the demand for middle distillates, thus creating excess motor gasoline.

Texaco predicted that motor gasoline demand would grow slowly and steadily from existing levels to 669 Mb/d in 1980 and 859 Mb/d in 1995. Texaco assumed that projected government fuel efficiency guidelines would be achieved, less 10 percent for road efficiency, but Texaco observed a trend toward an increase in miles driven and in the number of vehicles per family and a continuing trend toward smaller cars. Only in the extreme case, with heavy legislation and enforcement of vehicle size and speed limits, was demand expected to be lowered.

Views of the Board

The Board's forecast of the demand for motor gasoline in Canada is compared to the submitted forecasts in Figure IV-2.

It is estimated that in 1975 automobiles consumed about 80 percent of the motor gasoline demand, with the remaining 20 percent consumed by other vehicles, mainly trucks. As outlined in the detailed methodology section in Appendix J, gasoline demand for passenger cars is assumed to vary with the number of persons in the driver-age population, real personal disposable income, the unemployment rate, the consumer price index, indices of prices of cars by type (subcompact, compact, intermediate and full-size), the gasoline price index, the ratio of urban mileage to total mileage, and fuel economies. The Board's assumptions regarding total population, real disposable income, the unemployment rate and the consumer price index have been presented previously (see Table III-3).

Fuel economies for subcompacts and compacts are assumed to increase at an average annual rate of 6.6 percent over the 1976 to 1985 period, while intermediate and standard (full-size) fuel economies are assumed to increase slightly less rapidly at 5.5 percent per year over the same period. After 1985, fuel economies are assumed to remain constant. Table IV-3 displays the resulting levels of fuel economies by car type.

The trend toward smaller cars (subcompact and compact) is estimated to increase gradually over the 1976 to 1980 period, but to escalate rapidly thereafter. It is estimated that in 1995 the proportion of subcompact and compact models in total new car sales will range from 74 percent in Alberta to 90 percent in British Columbia.

Based on the assumed population forecast, and the forecast total number of cars, the persons per car ratio is estimated to decline from 2.65 in 1974 to approximately 2.24 persons per car in 1985. A ratio of two persons per car is projected to be reached in the early nineties, and is assumed to remain at that level thereafter.

Table IV-3

FUEL ECONOMIES BY CAR TYPE
NEB Assumptions
(Miles per gallon)

Year	Sub-Compact		Compact		Intermediate		Full-size	
	City	Other	City	Other	City	Other	City	Other
1974*	21.0	26.0	19.0	24.0	14.0	18.0	10.0	14.0
1980	29.6	36.5	26.8	33.7	19.7	25.3	14.0	19.7
1985	42.7	52.7	38.6	48.6	25.1	32.3	17.9	25.1
1995	42.7	52.7	38.6	48.6	25.1	32.3	17.9	25.1

* *Actual*

Estimated average miles travelled are assumed to depend on the age of the vehicle, as well as per capita income, the unemployment rate, and the price of gasoline. As a result of these factors, the average number of miles travelled is projected to gradually decline over the forecast period. In Ontario and Quebec for example, the average mileage declines slowly from 9,200 miles per car in 1975 to approximately 9,000 miles in 1995.

The proportion of urban mileage in total mileage travelled by car type is assumed to be 63 percent for subcompacts, 60 percent for compacts, 62 percent for intermediates, and 59 percent for full-sized cars.

The above fuel economies combined with the estimated new car sales reflect the achieving of standards set by the Minister of Energy, Mines and Resources, stipulating that manufacturers' new car fleets will be required to average 24 miles per gallon by 1980, and 33 miles per gallon by 1985.

It is assumed that the proportion of truck consumption of motor gasoline will increase from about 20 percent in 1975 to 25 percent in 1980, given an expected vigorous rate of growth in truck sales, and moderate increases in their fuel economies.

The combined demand for motor gasoline in Canada by cars and other vehicles is estimated to be 607 Mb/d in 1976 and 638 Mb/d in 1995 with a peak of 677 Mb/d reached in 1985. Over the 1976 to 1980 period the demand for motor gasoline is forecast to increase at an average annual rate of 2.3 percent. This rate is considerably lower than the historical rate of 5.5 percent over the period 1966 to 1974. The lower rate of growth during the 1976 to 1980 period is attributable partly to the effect of higher real gasoline prices in reducing automobile sales and partly to the effect of greater fuel economies in new car models.

The forecast average annual rate of growth of gasoline demand reduces to 0.4 percent over the 1980 to 1985 period, and during the 1985 to 1990 period demand for motor gasoline is forecast to decline at a rate of some 1.1 percent per year. The trend in gasoline consumption in the post 1980 period is explained mainly by the increasing predominance in the automobile stock of models with significantly higher fuel economies combined with a continuous shift towards smaller cars. Gasoline demand is forecast to remain stable during the 1990 to 1995 period. These results stem largely from incorporating into the demand models the proposed government automobile efficiency standards. If the standards are not met, motor gasoline demand could be considerably higher than estimated here.

The Board's forecast of motor gasoline demand is somewhat higher than those of Gulf and Shell over most of the forecast period, but significantly lower by 1995 than those of Imperial and Texaco. Imperial's forecast is higher than the Board's mainly as a result of its faster rate of increase in gasoline consumption in the non-automobile segment. Texaco's forecast of gasoline consumption under its most likely conservation case is higher than the Board's forecast mainly due to its assumption that the number of miles driven per year will increase, as opposed to the Board's assumption that the average number of miles travelled per vehicle will decline gradually, as the number of vehicles per family increases.

Regional variations in the Board's estimated annual rates of growth in gasoline demand are significant as may be noted in Appendix I.

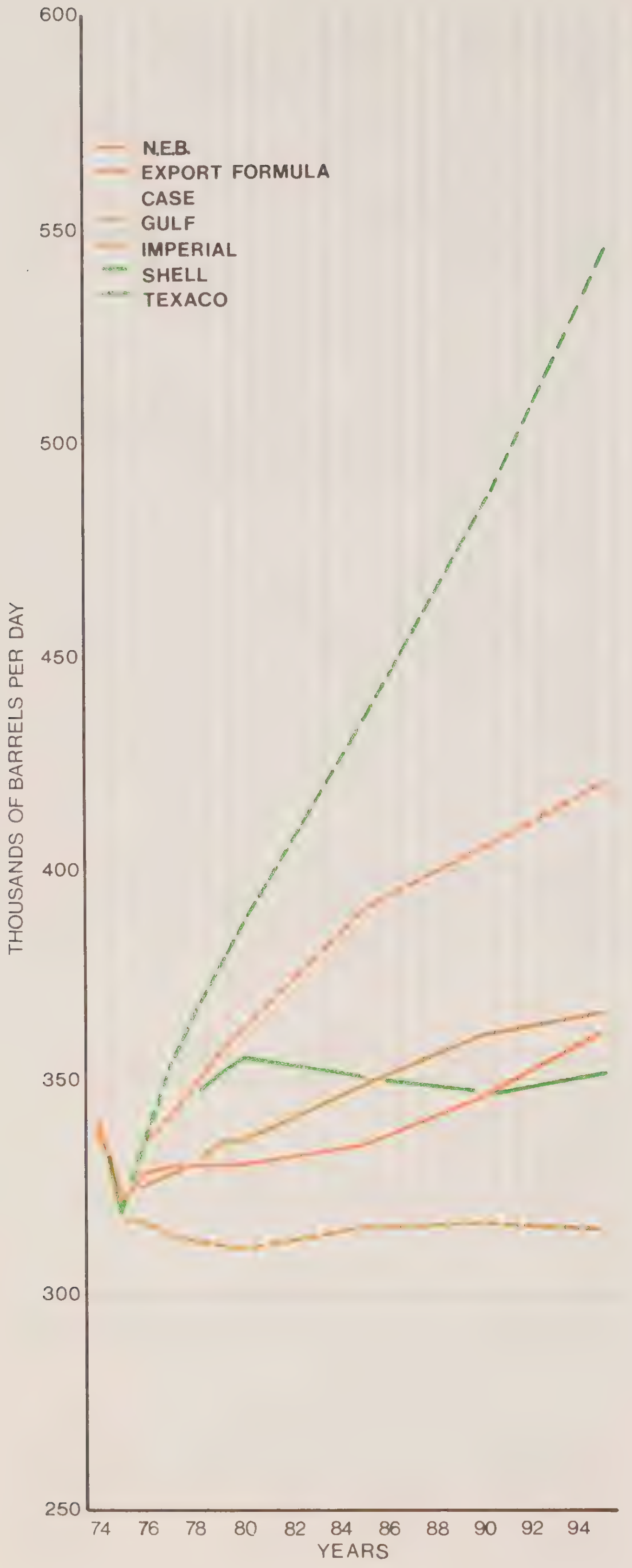
LIGHT FUEL OIL, KEROSENE AND STOVE OIL

Views of Submittors

The submittors' most likely forecasts of demand for light fuel oil, kerosene and stove oil are compared graphically in Figure IV-3.

Gulf expected the demand for heating fuels to grow only slightly throughout the forecast period largely as a result of the impact of conservation measures.

Imperial indicated that heating fuel demand would decline slightly until 1980, and then would increase marginally to 314 Mb/d in 1995. Demand was predicted to be constant at 180 Mb/d EOV until 1980, and then to grow to 195 Mb/d in 1995. Demand



WOV was expected to decline slightly and steadily throughout the forecast period.

Shell expected oil heating fuels to be subject to competitive pressure from both natural gas and electricity. Competition from natural gas was assumed because of its lower price, and from electricity because of lower home installation costs. Heating oil prices were expected to encourage lower space heating consumption and a trend towards types of dwelling which have less energy consumption per household. As a result, demand for light fuel oil was expected to reach a peak of 353 Mb/d in 1980 and remain near that level thereafter.

Texaco assumed in its heating oil forecast, a trend toward multiple housing, increased insulation and more efficient oil burners. Competition from natural gas was assumed as the use of natural gas was restricted to residential and specialty uses. Demand was expected to grow throughout the forecast period.

Views of the Board

The Board's forecast of demand for light fuel oil, kerosene and stove oil is also shown in Figure IV-3.

Light fuel oil is used mainly in the residential sector for space heating purposes. As a result of the relative price assumptions and assumed differences in heating system installation costs, significant penetration of the space heating market by both natural gas and electricity is expected. The market share of light fuel oil in the residential sector is forecast to decline from an actual 38.8 percent in 1974 to 33.6 percent in 1980, and 25.4 percent in 1995. Total energy demand in the residential sector does not grow fast enough to offset this declining light fuel oil market share. The estimated demand for light fuel oil declines slowly at an average annual rate of 0.5 percent over the forecast period.

Figure IV-3. **DEMAND FOR LIGHT FUEL OIL, KEROSENE AND STOVE OIL**
Comparison of Forecasts

On a regional basis, with the exception of the Atlantic region, residential sector demand for light fuel oil declines slowly over the forecast period. In the Atlantic region demand is expected to increase at an average annual rate of 2.0 percent over the forecast period because electricity is expected to continue to be relatively expensive and natural gas is assumed to remain unavailable over the forecast period.

Total demand across all sectors for light fuel oil, kerosene and stove oil is forecast to increase from an actual level of 321 Mb/d in 1975 to 360 Mb/d in 1995, at an average annual growth rate of 0.5 percent over the forecast period. Demand in all sectors remains relatively constant over the 1976 to 1980 period, increasing slowly thereafter as demands in the commercial and industrial sectors continue to increase and offset the small decline in the residential sector. Over the period 1976 to 1995, annual growth in demand for light fuel oil, kerosene and stove oil is highest in the Atlantic region at 2.2 percent; in Ontario demand is expected to decline at a rate of 0.6 percent per annum.

The Board's forecast of demand for light fuel oil, kerosene and stove oil is similar to Gulf's forecast for total Canada. Shell's forecast is similar to the Board's forecast by the end of the forecast period, although it is as much as 7 percent higher in the initial part. Imperial's forecast is lower than the Board's forecast partly as a result of Imperial's assumption that after 1980, the natural gas service areas in Quebec and British Columbia will expand coincident with the availability of Beaufort Sea gas. Texaco's forecast is significantly higher than those of the Board and the other submittors mainly as a result of Texaco's assumptions that the consumer will be reluctant to make the capital investments necessary to conserve energy, and that the use of natural gas will be restricted to residential and specialty uses.

DIESEL FUEL OIL

Views of Submittors

The submittors' most likely forecasts of the demand for diesel fuel oil are compared graphically in Figure IV – 4.

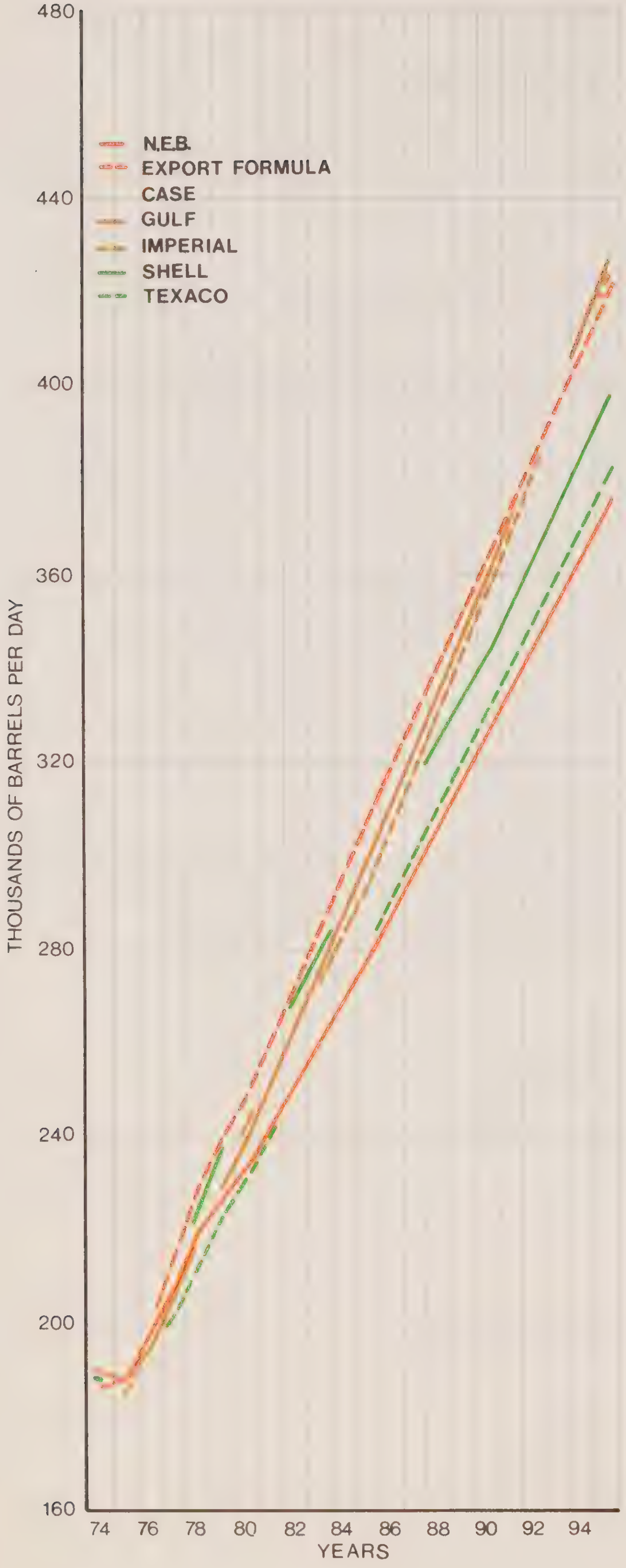
Gulf expected diesel fuel oil demand to grow consistently with historical trends and economic expectations. Gulf also expected diesel truck and bus registrations to continue to rise as a percent of total registrations in 1995.

Imperial predicted comparatively strong growth in diesel demand throughout the forecast period.

Shell predicted an uneven impact of conservation on demand because some uses of diesel fuel in the transportation, industrial and farm sectors are not amenable to conservation measures.

Sun predicted strong growth averaging 5 percent per annum throughout the forecast period in the regions in which it operates.

Texaco expected diesel fuel demand to continue to be strong given the demand for the transport of goods by equipment utilizing diesel fuel.



Views of the Board

As Figure IV – 4 indicates, the Board's estimates of the demand for this product are fairly close to those of submittors.

Diesel fuel oil is consumed primarily in the industrial, rail transportation and road transportation sectors. Small quantities are also consumed in the marine transportation, residential (farm) and commercial sectors. The relative importance of diesel fuel in the fuel consumption mix of these sectors can be seen on pages 1 and 2 of Appendix H.

Total diesel fuel demand is expected to grow from an estimated 200 Mb/d in 1976 to 235 Mb/d in 1980 and 375 Mb/d in 1995. In terms of rates of growth this represents an average annual increase of 4.1 percent from 1976 to 1980 and 3.2 percent from 1980 to 1995. The growth of diesel fuel demand is approximately the same on both sides of the Ottawa Valley Line.

Figure IV-4. **DEMAND FOR DIESEL FUEL OIL**
Comparison of Forecasts

HEAVY FUEL OIL

Views of Submittors

The submittors' most likely forecasts of the demand for heavy fuel oil are shown graphically in Figure IV – 5. The range between submittors' estimates of the demand for heavy fuel oil is narrow, although Texaco's estimate is somewhat higher than the others for the later part of the forecast period.

Gulf expected heavy fuel oil demand to increase steadily from the current levels. For example, in New Brunswick, the needs of the Coleson Cove generating plant were expected to be 27.4 Mb/d by 1980 and Ontario Hydro's requirements were expected to be 33.7 Mb/d for the period of the forecast.

Imperial's demand predictions were higher than Gulf's as Imperial assumed that oil would retain its share of the industrial market during the forecast period.

Ontario Hydro estimated its requirements for the Lennox, Wesleyville and Bruce installations to decrease to 8.5 Mb/d in 1977 from 13.7 Mb/d in 1976, and to vary between 21 to 27 Mb/d from 1978 to 1980 and between 28 to 30 Mb/d in 1985, 1990 and 1995.

Shell expected comparatively strong demand increases through to 1980 owing to improved economic activity, competitive constraints on prices and commissionings of new thermal electric generating plants. Beyond 1980 the growth rate was expected to decline to 1.7 percent per annum.

Sun expected growth rates for heavy fuel oil of 2, 3 and 4 percent in the Ontario, Quebec and the Atlantic regions respectively throughout the forecast period.

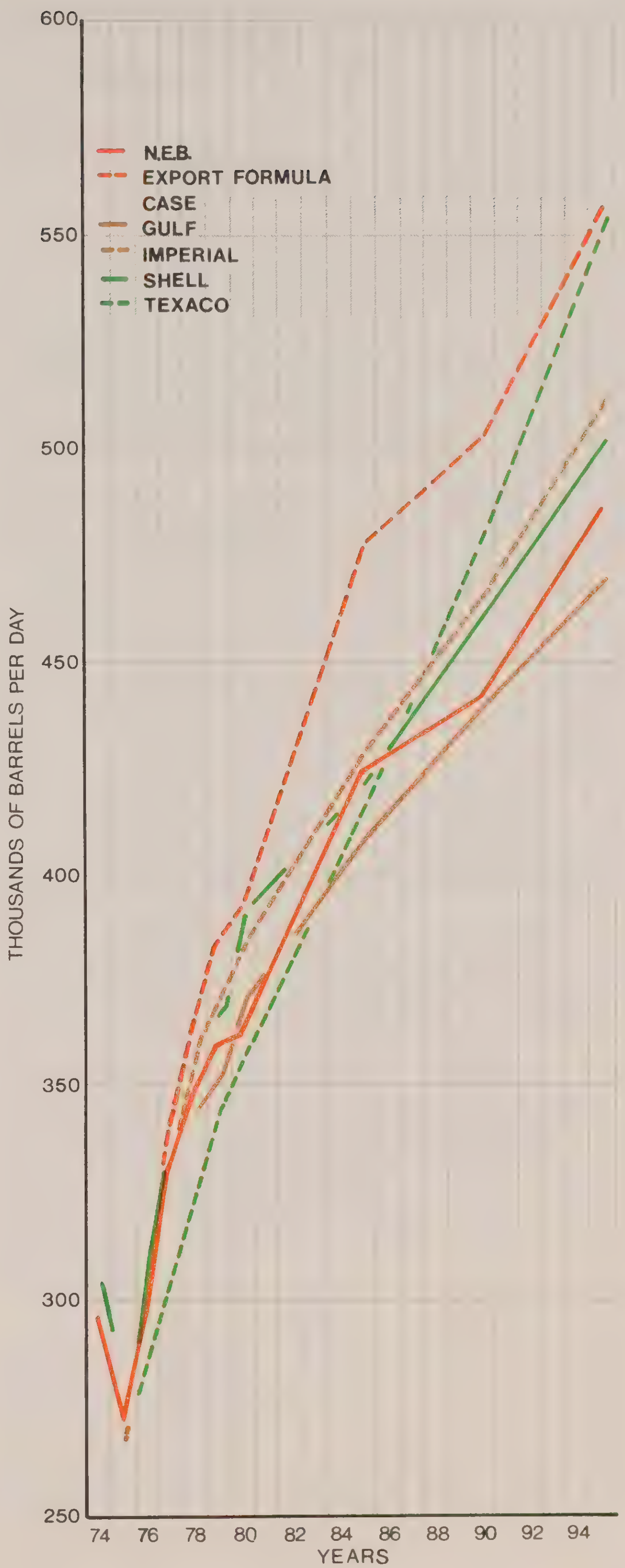


Figure IV-5. **DEMAND FOR HEAVY FUEL OIL**
Comparison of Forecasts

Texaco expected heavy fuel oil to be in high demand for electric generation in the near term, with total demand growing steadily to 553 Mb/d in 1995.

Views of the Board

The Board's forecast of the demand for heavy fuel oil is also presented in Figure IV – 5.

Heavy fuel oil demand in Canada is forecast to increase from 297 Mb/d in 1976 to 487 Mb/d in 1995, implying an average annual growth rate of 2.6 percent over that period.

By end-use, most of the consumption takes place in the industrial sector, although significant quantities are also consumed in the commercial sector. In some regions, however, consumption for marine transportation and thermal electric generation is also significant. On a regional basis most of the consumption of heavy fuel oil occurs in Quebec, the Atlantic region and Ontario as shown in Appendix I.

Heavy fuel oil demand in Quebec, which accounted for almost 40 percent of Canada's heavy fuel oil demand in 1975, is forecast to grow quite rapidly, at 4.8 percent per year between 1976 and 1980, slowing to 2.8 percent per year between 1980 and 1995, for an average growth of 3.2 percent over the whole forecast period. This demand is expected to grow faster prior to 1980 than afterwards in all three of the major consuming sectors – industrial, commercial, and marine. Prior to 1980, the demand for heavy fuel oil grows fastest in the marine transportation sector, with slower growth in the industrial and commercial sectors. Commercial demand is forecast to increase relatively slowly because of expected market penetration by electricity.

Industrial demand in Quebec, which accounted for approximately 56 percent of total heavy fuel oil demand in 1974, is forecast to increase at an average annual rate of 4.0 percent between 1976 and 1980, slowing to 3.7 percent between 1980 and 1995. The relatively rapid growth before 1980 reflects the fact that demand was depressed in 1975 as a result of a general economic slowdown and several prolonged strikes, but it is expected to rise to levels more in keeping with longer term historical trends. A recent Board survey of large industrial consumers of heavy fuel oil in Quebec indicates that while industrial demand is not thought to have been much higher in 1976 than it was in 1975, relatively rapid growth is expected in 1977 (in the order of 6.0 percent).

Over the longer term in the absence of gas franchise extension, the market share of heavy fuel oil in the industrial sector in Quebec is assumed to continue to increase slowly, as it has in the past. Heavy fuel oil is not expected to lose market share to natural gas because it is assumed that the two energy types will be priced competitively in the industrial market in Central Canada over the forecast period.

Atlantic region demand for heavy fuel oil, which accounted for approximately 27 percent of consumption in Canada in 1975, is forecast to grow at an average annual rate of 2.7 percent between 1976 and 1995. This forecast does not take into account possible circumstances which might give rise to the development of a natural gas market. Roughly 46 percent of this consumption consisted of requirements for electricity generation; of the remaining 54 percent, it is estimated that slightly less than half was consumed in the industrial sector.

In the Atlantic region, demand for electricity generation is forecast to increase from an actual level of 34 Mb/d in 1975 to 63 Mb/d in 1977, and 86 Mb/d in 1985, and then to decrease to 59 Mb/d in 1990 and 58 Mb/d in 1995. This forecast was developed through an examination of electric utility forecasts in the four Atlantic provinces. The large increase in 1977 reflects the expected heavy fuel oil demand for the generation of electricity at Coleson Cove, New Brunswick, which commenced operations in 1976.

For purposes other than electricity generation, demand for heavy fuel oil in the Atlantic region is forecast to grow at an average annual rate of 3.1 percent over the forecast period. Both industrial and commercial demands are forecast to grow more slowly before 1980 than afterwards, reflecting increases in the real price of energy in the earlier period. In both sectors the market share of heavy fuel oil decreases slowly over time, with further market penetration by electricity in line with historical

trends. Demand in the marine sector is also forecast to increase faster before 1980 than afterwards.

Total heavy fuel oil demand in Ontario, which accounted for approximately 22 percent of Canadian demand in 1975, is forecast to grow at 4.2 percent per year between 1976 and 1980, slowing down to 1.2 percent per year between 1980 and 1995, yielding a relatively low rate of growth over the entire period of 1.9 percent per year.

Industrial demand in Ontario, which accounted for 48 percent of the provincial total demand for heavy fuel oil in 1974, is forecast to increase rather rapidly between 1976 and 1980 (4.2 percent per year), but at only 2 percent per year between 1980 and 1995. The higher growth before 1980 reflects the fact that demand was depressed in 1975, and is expected to move back towards longer term trends over the next few years. This expectation is consistent with the results of a recent Board survey of large industrial consumers of heavy fuel oil in Ontario. Over the longer period, the market share of heavy fuel oil is expected to decrease slowly in the industrial sector of Ontario, reflecting a continuation of some market penetration by electricity related to specialty energy applications.

Residential and commercial demands for heavy fuel oil, which together accounted for approximately 38 percent of Ontario's demand for this product in 1974, are forecast to decrease over the forecast period. This decrease is expected to take place at a slightly higher rate after 1980 than before, because of expected market penetration by both natural gas and electricity.

In 1975 heavy fuel oil demand for the generation of electricity in Ontario was 4 Mb/d. This demand was estimated to increase sharply in 1976 to 16 Mb/d with the start-up of the Lennox generating station. Following an expected drop in the level of the heavy fuel oil thermal demand in 1977, demand is forecast to increase to 21 Mb/d by 1978 and thereafter to grow at about the same rate as predicted by Ontario Hydro.

PETROCHEMICAL FEEDSTOCKS

Views of Submittors

The submittors' most likely forecasts of demand for petrochemical feedstocks are shown graphically in Figure IV – 6.

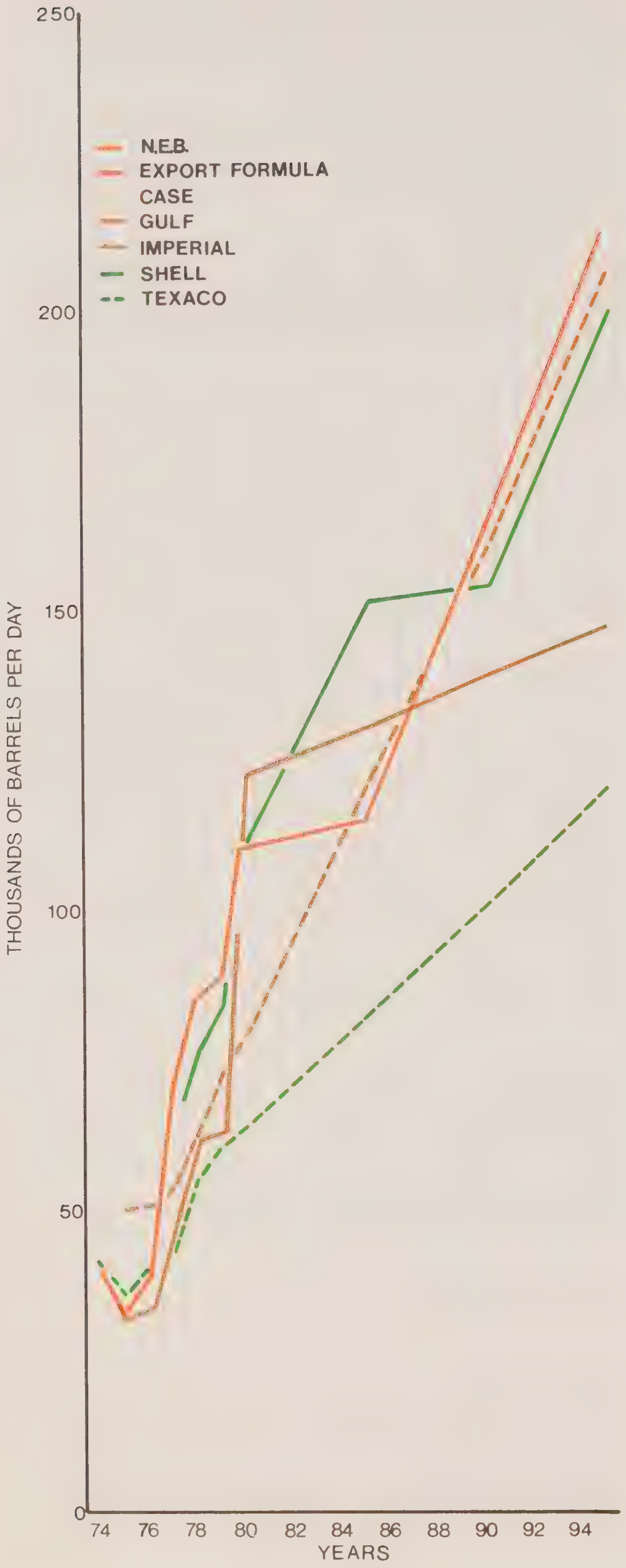
Gulf indicated that petrochemical feedstocks demand would rise from 34 Mb/d in 1976 to 147 Mb/d in 1995. Growth in the first period included Petrosar Limited ("Petrosar") demand increasing from 13 Mb/d in 1977 to 35 Mb/d in 1980. Although Gulf assumed a 50 Mb/d aromatics plant would come on stream in Alberta in 1980, in subsequent testimony Gulf indicated its skepticism as to the need for such a plant and explained that it considers refining capacity at Edmonton sufficient, with some modification, to produce the benzene if and when the demand were to materialize.

Imperial suggested that petrochemical demand would rise from 51 Mb/d in 1976 to 80 Mb/d in 1980 and 206 Mb/d in 1995. Prairie demands were expected to be minimal at 2 Mb/d until 1985 when demand was indicated to grow to 15 Mb/d reflecting a small plant in Alberta. Ontario demands were expected to grow steadily from 30 Mb/d in 1976 to 120 Mb/d in 1995.

Petrosar indicated that its primary petrochemical demand would increase from 27 Mb/d in 1977 to 44 Mb/d by 1980. By 1995, demand would be 46 Mb/d.

Shell assumed that three new petrochemical facilities would be built in Alberta. Two naphtha-based ethylene plants each requiring 40 Mb/d were assumed to come on stream, one in 1985 and the other in 1994. A condensate-based benzene facility requiring 45 to 50 Mb/d was also assumed for 1980. This resulted in petrochemical demands rising from 41 Mb/d in 1976 to 200 Mb/d by 1995.

Texaco assumed rapid growth in demand for petrochemical feedstocks from 1977 to 1980 as a result of the Petrosar operation. Demand was expected to grow to 64 Mb/d in 1980 and 120 Mb/d by 1995. Texaco did not assume that the condensate-based benzene projects would go ahead.



Views of the Board

The Board's forecast of demand for petrochemicals feedstocks is also presented graphically in Figure IV – 6.

Most of the forecast increase in feedstock requirements results from projected increases in Ontario and Alberta. For the other regions, no major oil-based petrochemical plant additions or expansions are anticipated at this time and consequently demand is projected to follow historical trends. The assumptions underlying the demand forecasts for Ontario and Alberta are presented below.

Petrosar is assumed to come on stream in Ontario in 1977, with a naphtha demand for the production of petrochemicals of 27 Mb/d in that year, rising to 46 Mb/d in 1985. Both the level and the timing of demand reflect hearing evidence of Petrosar.

A second world-scale naphtha-based ethylene plant is assumed to commence operations in 1990. Feedstock demand by this plant is assumed to be the same as for Petrosar: 46 Mb/d.

Two major additional plants are assumed to begin operating over the period 1976 to 1995; a condensate-based benzene plant in 1980 with feedstock demand of 20 Mb/d, and a world-scale naphtha-based ethylene plant in 1995, requiring 46 Mb/d of feedstocks.

Figure IV – 6 illustrates significant variance in forecast demands for petrochemical feedstocks, reflecting different assumptions made by submittors and the Board as to the number and timing of various petrochemical projects in Canada over the forecast period. Texaco has the lowest forecast demand as a result of its assumption that Alberta feedstock requirements would not increase beyond 2 Mb/d over the forecast period.

Figure IV-6. **DEMAND FOR PETROCHEMICAL FEEDSTOCKS**
Comparison of Forecasts

OTHER PRODUCTS

For purposes of this report, the other products category consists of refinery-produced propane and propane mixes, butane and butane mixes, naphtha specialties, aviation gasoline, aviation turbo fuel, asphalt, coke, lubricating oils and greases and waxes. The submittors' most likely forecasts and the NEB forecast of demands for other products are compared graphically in Figure IV – 7.

Views of Submittors

Strong growth in this product group was predicted for aviation turbo fuels particularly. Shell cited a shift toward kerosene based jet fuels contributing to an overall increase in middle distillate demand. Texaco also predicted comparatively high rates of growth for jet fuels. The lowest estimate for other product demand in 1980 was 211 Mb/d, while the highest estimate was 255 Mb/d. The lowest forecast of demand for 1995 was 338 Mb/d; the highest was 447 Mb/d.

The IPAC submission contained an econometric model for asphalt demand which predicted total demand, excluding the Atlantic region, to be 58.3 Mb/d in 1981 and 87.9 Mb/d in 1995. Approximately 68.1 Mb/d of the 1995 estimate was paving demand and the remainder was roofing demand. Quebec demand was expected to be 14.7 Mb/d in 1981 and 20.7 Mb/d in 1995. Ontario demand was predicted to be 18.5 Mb/d in 1981 and 28.5 Mb/d in 1995.

Views on expected growth in asphalt demand were also submitted by Husky and PanCanadian Petroleum Limited ("PanCanadian"). Husky expected demand to be 12.5 Mb/d in Quebec and 16.3 Mb/d in Ontario by 1980. Husky predicted demand to be 17.0 Mb/d by 1995 in Quebec and 22.3 Mb/d in Ontario. PanCanadian expected demand of 13.7 Mb/d for Quebec and 17.8 Mb/d for Ontario in 1980. Demand was predicted at 22.6 Mb/d for Quebec and 20.4 Mb/d for Ontario in 1995.

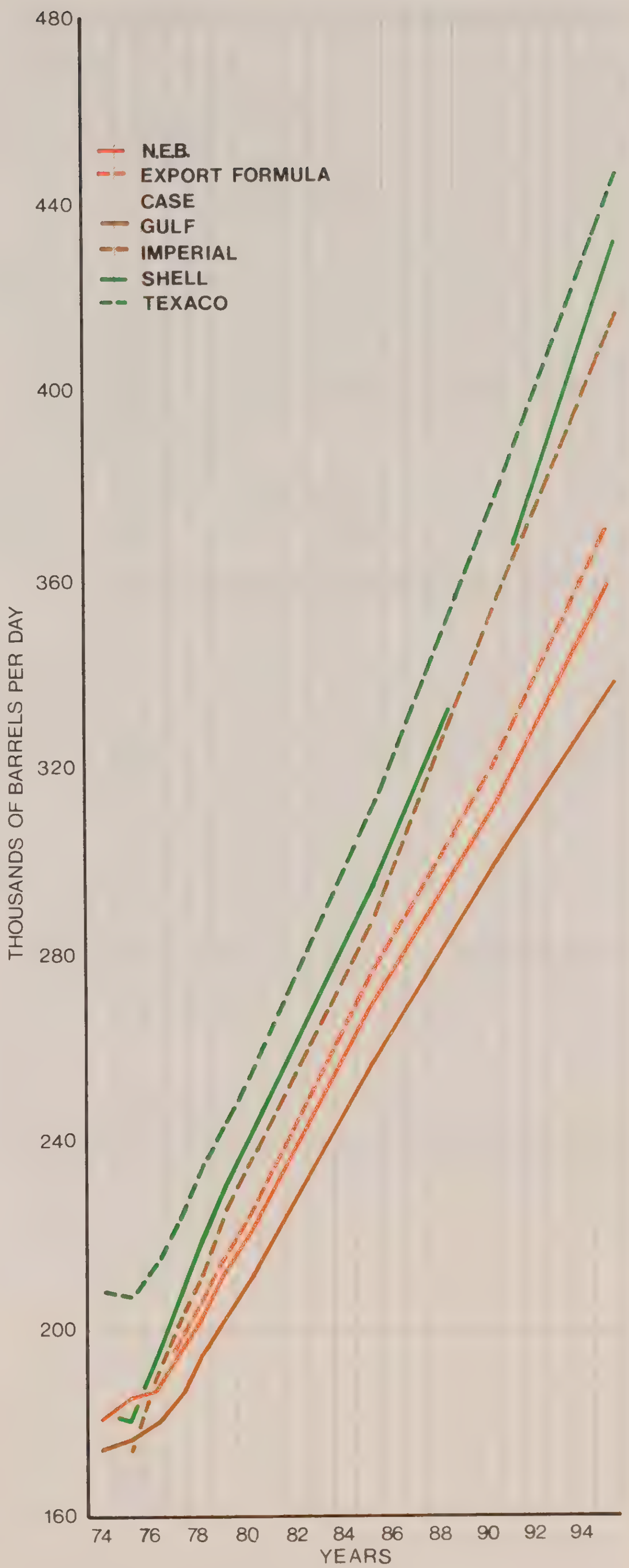


Figure IV-7. **DEMAND FOR OTHER REFINED PETROLEUM PRODUCTS**

Comparison of Forecasts

Views of the Board

Asphalt and aviation turbo fuel are the two major components in the other products category, respectively comprising 26 percent and 35 percent of the product volume of this category in 1975.

As shown on Figure IV – 7 and in Appendix I, demand for other products is expected to increase from 187 Mb/d in 1976 to 220 Mb/d in 1980 and to 360 Mb/d in 1995. This represents an average annual growth rate of 4.2 percent in the 1976 to 1980 period and 3.3 percent in the 1980 to 1995 period.

The Board's forecast of the demand for aviation turbo fuel exhibits strong growth over the forecast period, averaging 4.5 percent per year. Such growth is consistent with expectations of the submittors regarding demand for this product.

The demand for asphalt is projected to average 3.7 percent per year over the forecast period, increasing from an estimated 50 Mb/d in 1976 to 104 Mb/d in 1995. Growth is more rapid over the 1976 to 1980 period at 5.0 percent per annum, slowing over the remainder of the forecast period to 3.5 percent per annum, as the growth in real domestic product slows. For Canada, excluding the Atlantic region, the Board's forecast demand for asphalt is 57.5 Mb/d in 1981, growing to 94.1 Mb/d in 1995. These estimates are similar to those of IPAC, whose corresponding estimates were 58.3 Mb/d and 87.9 Mb/d respectively.

For the reasons outlined in the Board's September 1975 report on Oil Supply and Requirements, the potential for conservation is limited for most of these products.

Requirements for Feedstocks

Future Canadian requirements for indigenous feedstocks derive not only from forecast demands for petroleum products within Canada, but also from the effects of refiners' and marketers' decisions and plans regarding product imports, regional transfers, refinery utilization, construction of new facilities, closing of existing plants and the future opportunities to sell Canadian products in foreign markets. It is not surprising, therefore, that forecasts of crude requirements provided to the Board should exhibit considerable variation. Appendix L summarizes these forecasts (as well as the Board's) and shows that the variation becomes more pronounced in the latter years of the forecast period. For the purposes of this report Transfers refers to those products which are transferred across the boundary known as the Ottawa Valley Line. Losses and Industry Use are determined by the level of refinery runs and the products manufactured. Receipts of gas plant butanes are deducted from total feedstock demand to arrive at the requirements for crude oil and equivalent.

In addition to requesting the views of submittors on the requirements for total crude oil and equivalent in Canada, the Board invited submittors to provide projections concerning future requirements for indigenous heavy crude oil. Accordingly, this chapter consists of the following sections:

- requirements for total crude oil and equivalent, and
- requirements for indigenous heavy crude oil.

Appendix L presents the forecasts of total crude oil and equivalent prepared by four major submittors and by the Board. Appendix M presents details of the Board's forecast of requirements for indigenous heavy crude oil. The projected requirements for light crude oil and equivalent shown in Appendix N were determined by subtracting the requirements for indigenous heavy crude oil from the requirements for total indigenous crude oil and equivalent.

REQUIREMENTS FOR TOTAL CRUDE OIL AND EQUIVALENT

Views of Submittors:

The submitted forecasts of requirements for total crude oil and equivalent are compared graphically in Figures V-1 to V-3. The forecasts roughly parallel the total product demand forecasts upon which they were based. Thus, of the four major oil companies' forecasts of crude requirements for the post-1980 period, Texaco's was the highest, followed by Imperial's, Shell's and Gulf's. All four included the effects of conservation in their forecasts. However, they reflected differing assumptions regarding product imports, exports and transfers across the Ottawa Valley Line. Net transfers were generally forecast to continue in a westward direction; however, Shell assumed net transfers would disappear by 1980 and Imperial showed net transfers from the west to the east starting in 1985. An underlying assumption in most of these forecasts appears to be that large heavy fuel oil transfers, mainly to Ontario Hydro, will continue through the period.

For the area WOV most forecasts showed continued product imports primarily because of local shortfalls of specific products rather than any over-all deficiency in crude oil refining capacity. Product exports were forecast by all submittors but there was considerable variation among the various forecasts; for example, refined petroleum product exports in 1980 ranged from 35 Mb/d (Imperial) to 82 Mb/d (Texaco) and in 1995 from 12 Mb/d (Imperial) to 110 Mb/d (Shell). The highest estimate of the average annual rate of growth in WOV feedstock requirements for the period 1976-1995 was 3.1 percent submitted by Texaco; the lowest, 2.2 percent was provided by Gulf.

In the area EOV, product imports were forecast by Gulf and Shell to be zero in some years and only relatively small volumes were shown in other years. Imperial, on the other hand, showed substantial product imports: for 1980 it projected 109 Mb/d. EOV product export forecasts showed considerable variation: for example, they ranged from 28 Mb/d (Imperial) to 110 Mb/d (Texaco) for 1980 and from

zero (Imperial) to 156 Mb/d (Shell) for 1995. Texaco's estimate of average growth of EOV feedstock requirements, including the effects of conservation, for the period 1976-1995 was the highest submitted at 2.9 percent; the lowest was Imperial's 1.8 percent.

Views of the Board

The Board's forecast of requirements for crude oil and equivalent are also shown on Figures V-1, V-2 and V-3.

In the current circumstances affecting the supply and distribution of indigenous feedstocks, the Board finds it difficult to contemplate processing by WOV refineries at levels that would give rise to output surplus to Canadian product demand "across the barrel", i.e. supply that is surplus in terms of all main products (gasoline, distillates and residual oils). Indeed, the Board would like to see WOV refineries capable of processing domestic supplies to yields that more closely match the product mix of Canadian demand. In general terms, the Board's view is that the aggregate runs of indigenous crude oil at WOV refineries should be at levels sufficient to meet local demands for light products, with minimal surpluses of motor gasoline or middle distillates and with checks imposed on incremental processing that provides extra product for export. However, the Board recognizes that it is by no means simple to lay down hard and fast guidelines — for example, as to what part of any surplus may be regarded as necessarily made in the manufacture of product

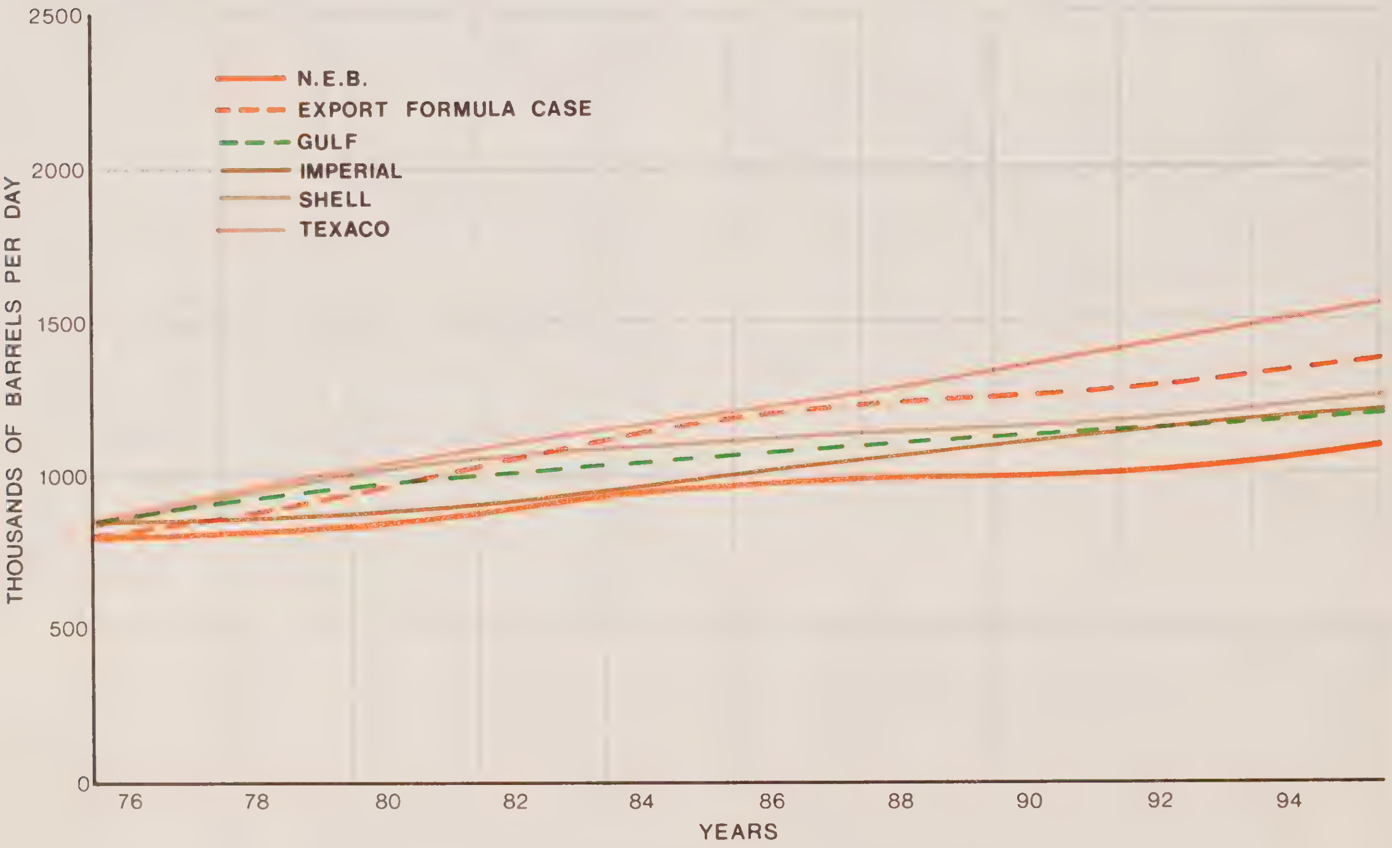


Figure V-1. **REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT, EOV**
Comparison of Forecasts

needed for Canadian consumption. Nevertheless, the growth of refining capacity which depends on indigenous feedstocks increasingly calls for closer attention to these matters.

With the data currently available, the Board estimates that in the period 1977-1982 the WOV refineries, including the new Petrosar and Texaco (Nanticoke) facilities, will produce considerable volumes of surplus co-products and in fact long-term (5-6 years) licences recently have been issued for the export of such residual products totalling 60 Mb/d. In projecting the post-1980 WOV requirements for feedstocks, the Board has assumed for present purposes that net product exports will fall from 66 Mb/d in 1980 to nominal levels by 1990. With respect to transfers, the Board has taken into consideration evidence submitted by Ontario Hydro that the present supply contract for heavy fuel oil from Quebec will expire in 1979. Although Ontario Hydro expressed the expectation that a new contract will provide for 1980 and beyond, the Board has assumed that large transfers of heavy fuel oil will not continue after 1979. The Board's estimate of the average annual rate of growth for WOV requirements for crude oil and equivalent in the period 1976-1995 is 2.5 percent based on its forecast of refined petroleum product demand and 3.8 percent for the Export Formula Case.

For the area EOV, the Board foresees that the refinery capacity presently in place (excluding the

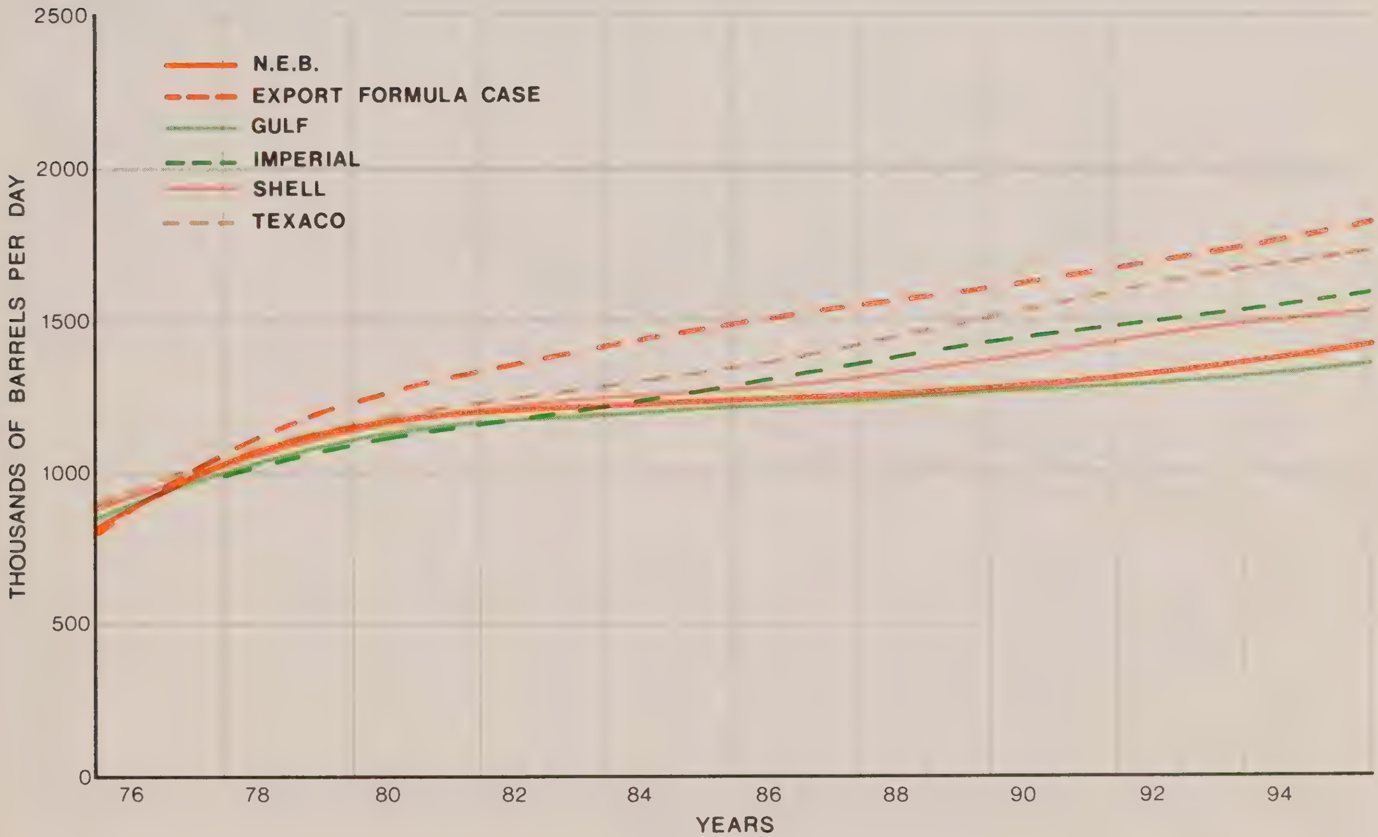


Figure V-2. **REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT, WOV**
Comparison of Forecasts

shut-down refinery at Come-by-Chance, Newfoundland) will be in excess of local requirements until the post-1985 period. This circumstance coupled with uncertainty of the availability of foreign markets suggest that there could be large fluctuations in the relative levels of crude runs, product imports and product exports. In projecting the future crude requirements of the EOV refineries, the Board has assumed for present purposes that EOV refineries will be run to meet Canadian demands for light products. To the extent that export markets for these products exceed the assumed nominal levels, the crude requirements shown in Appendix L could be understated. Substantial volumes of heavy fuel oil imports are assumed because the demand for this material in the Atlantic region is forecast to increase its share of the total product demand, and local refineries, if faced with restricted export markets for light products, will be unable to substantially increase their throughputs. The Board's estimate of the average annual rate of growth of the EOV requirements for crude oil and equivalent in the period 1976-1995 is 1.5 percent based on its refined petroleum product forecast and 2.7 percent for the Export Formula Case.

The average annual growth rate in the Board's forecast of requirements in Canada for crude oil and equivalent for the period 1976-1995 is 2.0 percent. In the Export Formula Case, the average annual rate of growth is 3.3 percent.

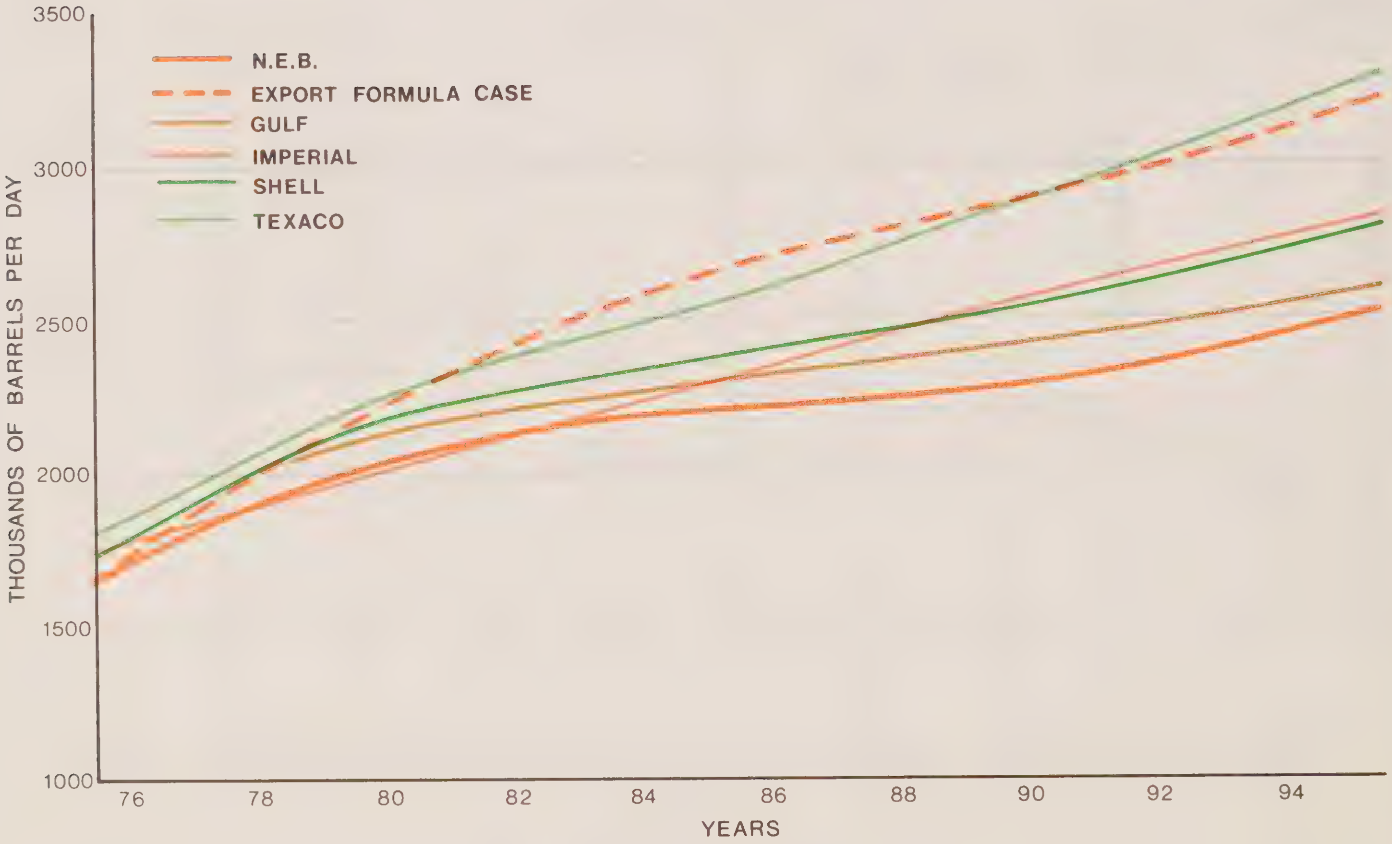


Figure V-3. **REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT, CANADA**
Comparison of Forecasts

The Board's forecast of requirements for indigenous crude and equivalent shown in Appendix N includes along with the WOV requirements, shipments of 250 Mb/d to EOV refiners.

REQUIREMENTS FOR INDIGENOUS HEAVY CRUDE OIL

Forecasts of requirements for indigenous heavy crude oil in Canada were submitted to the Board by the AERCB. Ashland Oil Canada Limited ("Ashland"), Gulf, Husky, IPAC, Murphy Oil Company Ltd. ("Murphy"), Pacific, PanCanadian and Shell. In most cases submittors related WOV requirements for Canadian heavy crude oil to forecast demand for asphalt in this area. Forecasts of requirements for indigenous heavy crude oil in the Montreal area were based on experience of heavy crude oil shipments to Montreal, provincial nominations available to August 1976, and judgements as to what general level of requirements may develop.

Views of Submittors

West of the Ottawa Valley

The Board heard evidence from the submittors mentioned above on the anticipated WOV requirements for indigenous heavy crude oil. Estimates of future requirements varied considerably among submittors which in part resulted from some submittors including the heavy gravity Midale crudes in the forecast and others excluding it. A summary of submissions of WOV requirements for heavy crude oil is given in Table V — 1.

It was generally accepted by submittors that WOV requirements for heavy crude oil would depend primarily on demand for asphalt. Specific exceptions to this were:

- requirements for the heavy Midale crudes which are not used for production of asphalt,

Table V-1

WOV REQUIREMENTS FOR INDIGENOUS HEAVY CRUDE OIL
Comparison of Forecasts
(Mb/d)

	AERCB*	Ashland*	Gulf**	Husky	IPAC**	Pacific**	Pan Canadian**	Shell*	NEB**
1976	50	42	75	85	68.3	61	65	46	74
1977	52	39	90	87		63	60	50	73
1978	65	42	97	90		65	62	52	73
1979	70	44	84	92		68	63	56	77
1980	73	53	85	94	99.2	70	70	58	80
1985	87	61	87	107	102.9	83	82	62	99
1990	105	78	89	119	116.7	99	94	62	115
1995	130	93	88	131	129.2	118	106	76	134

— *Requirements exclude Midale: **Requirements include Midale.
— IPAC's projections for 1981,86,91 are shown in 1980,85,90.
— AERCB assumes 15 Mb/d requirements for an upgrading facility phased in starting 1978.

- requirements for heavy crude oil feedstocks to an upgrading facility (included in AERCB anticipated requirements), and

- requirements for electric utilities (included in IPAC anticipated requirements).

Methods by which heavy crude oil requirements were related to demand for asphalt varied among companies. In some cases asphalt demand was independently estimated and the forecast was converted back to heavy crude oil requirements. In most instances, submittors determined growth assumptions on analysis of asphalt markets and applied such growth rates to current heavy crude oil requirements. Submittors generally conceded that although little heavy crude oil can be handled in the area, refiners have sufficient flexibility over feedstock choice to render more difficult the forecasting of requirements for heavy crude oil than that of demand for refined petroleum products.

Montreal Area

The estimates of requirements for indigenous heavy crude oil in Montreal that were submitted to the Board are shown in Table V — 2. Movements of crude oil to Montreal via the Sarnia-Montreal pipeline commenced in June, 1976. Consequently, at the time submittors were preparing evidence for the hearing they had as a basis heavy oil movements only for the period June to August, 1976. The forecasts submitted largely exhibit a projection of initial takes and nominations for heavy crude oil in Montreal by BP Canada Limited ("BP").

Several submittors presented evidence on the potential requirements for indigenous heavy crude oil in Montreal and, for production of asphalt, there seems to be consensus that the potential is 40 Mb/d. Although the submission by Ashland indicates that 80 Mb/d is the potential for use of indigenous heavy crude oil in Montreal, this estimate was based on the assumption that refiners would use this crude oil for manufacture of heavy fuel oil as well as asphalt.

Table V-2

MONTREAL REQUIREMENTS FOR INDIGENOUS HEAVY CRUDE OIL
Comparison of Forecasts
(Mb/d)

	AERCB	Ashland	Gulf(1)	Husky	IPAC(1)	Pacific	Pan Canadian(1)	Shell	NEB
1976	5	4	15	15	3	11	10	—	5
1977	15	10	30	15	20	11*	10	—	25
1978	20	10	30	15	20	12*	11	—	35
1979	25	10	30	15	20	12*	12	—	35
1980	30	11	30	15	20	13*	13	—	35
1985	37	12	—	15	—	15	—	—	35
1990	43	13	—	15	—	19*	—	—	35
1995	50	14	—	15	—	22	—	—	35

(1) These forecasts show values only to 1980 since the assumption was made that "reversal" of Sarnia-Montreal pipeline would occur in the period 1980-1985.

*Numerical values extrapolated by NEB

Submittors stated that the requirements for indigenous heavy crude oil in Montreal were primarily a function of the demand for asphalt and the price of Canadian crude oil relative to alternate offshore crude oil. The possibility that the Sarnia-Montreal pipeline would be reversed in the 1980's was widely cited as the reason that refiners would be unlikely to install facilities specifically to process indigenous heavy crude oil. The useful life of such facilities would be too short and the introduction of different feedstocks would also affect asphalt quality which the market would be slow to accept.

Views of the Board

West of Ottawa Valley

The Board's forecast of WOV requirements for heavy crude oil is based on the following approach:

A forecast of asphalt demand as outlined in Chapter IV is used as a basis for calculating future demand for asphalt-yielding crudes. The anticipated Canadian requirements for the heavier grades of crude from the Midale area in Southeast Saskatchewan are separately determined. The estimate of demand for asphaltic heavy crudes is added to the Midale estimate to generate total heavy crude oil requirements. The Board's definition of heavy crude oil and the reasons for inclusion of Midale are contained in Chapter VI.

It is estimated for the forecast period that transfers of asphalt from Quebec into Ontario will continue at historical levels of about 35 percent of Ontario asphalt demand. In the period 1971 – 1975 relative stability of this movement is noted. Asphalt imports and exports are expected to be negligible for the forecast period.

Asphalt production in British Columbia is for the most part derived from Boundary Lake crude oil and a forward estimate was made of the contribution of Boundary Lake crude to asphalt supply. The WOV requirements for heavy crude oil were adjusted accordingly.

The yield of asphalt from heavy crude oil used by the Board was determined from historical data. Calculations were made to adjust net sales of asphalt in the historical period 1971 – 1975 to determine the supply of asphalt derived from indigenous heavy crude oils. Adjustments include transfers into the area WOV from Quebec, use of Boundary Lake and imported crude oil to manufacture asphalt and imports and exports of the product. The factor obtained from adjusted asphalt supply in relation to domestic requirements for heavy crudes is 2.1 barrels of heavy crude oil per barrel of asphalt produced. Although this factor does represent a departure from values of 40 percent yield or a reciprocal of 2.5 quoted by some submittors the Board believes it best relates future asphalt demand and heavy crude oil requirements.

The Board's forecast of WOV requirements for heavy crude oil does not include provision for feedstocks required for an upgrading facility. Discussion of the likelihood of such a facility being built and implications respecting export policies can be found in Chapter VII.

Montreal Area

The Board's forecast of demand for indigenous heavy crude oil in Montreal is based primarily upon testimony presented at the hearing by those Montreal refiners which intend to run it. Gulf testified that commencing in mid-1977 it would take 10-12 Mb/d of indigenous heavy crude to Montreal at a summer winter ratio of 2:1; Imperial testified that commencing in the first quarter 1978 it would take 15 Mb/d at Montreal. The established requirements for heavy crudes by BP in Montreal are assumed to continue, resulting in a total requirement by 1978 of 35 Mb/d. To the Board's knowledge, Gulf, Imperial and BP are the only companies planning to run indigenous heavy crude oil in Montreal in the foreseeable future. Testimony by Shell and Texaco indicated that they were not interested in running indigenous heavy crude oil in Montreal. Submissions were not received on this matter from other Montreal refiners and it is assumed they will not utilize any. The Board's forecast provides for the volume of 35 Mb/d to remain constant from 1978 onward. It was not escalated with total requirements in Quebec, but is held constant as is the throughput of all crude oil moved to Montreal from Western Canada.

Licensing Procedures

In the Outline for Submissions, the Board requested views on the future supply of and requirements for the various types of crude oil and equivalent and desirable changes in licensing procedures for crude oil and equivalent and petroleum products. Up to the end of 1976, the Board had determined the total level of crude oil and equivalent exports without reference to the crude types.

Licensing procedures were addressed in a detailed manner by many submittors. The views expressed and the views of the Board on this subject are given below under the following headings:

- need for licensing by grade,
- definition of heavy crude oil,
- method of determining heavy crude oil surplus,
- exports of refined petroleum products, and
- other licensing considerations.

NEED FOR LICENSING BY GRADE

Views of Submittors

All submittors that addressed the topic expressed the view that exports of certain grades of crude oil and equivalent should be considered separately in the Board's licensing procedures. In most cases submittors favored special treatment for heavy crude oil only but some thought that condensate and synthetic crude oil should also receive separate consideration. Although the common recommendation concerning export policies for specific crude types was to allow production at capacity, this concept was variously expressed in such terms as:

- allow unrestricted exports of heavy crude oil,
- allow production and sales at maximum rates,
- license heavy crude oil separately, and
- exempt heavy crude oil from the licensing program.

Although the expression "to license separately" is an imprecise equivalent of the differing recommendations made, it is conveniently used in the discussion which follows to refer generically to them.

The Board received complete and well argued submissions as to why certain crude oils should be licensed separately. Among the reasons given in respect of heavy crude oil were these:

- Canadian heavy crude oil differs significantly from light crude oil in quality and thus in refining characteristics, in markets served, and in production circumstances,
- with reference to proven and potential reserves there are proportionately greater prospects for increasing the current levels of production of heavy than light crude oil,
- additions to heavy crude oil reserves and producibility could add substantially to Canada's self-reliance in oil,
- experimentation with enhanced oil recovery would proceed faster with assured marketability of heavy crude oil; such experimentation and coincident technological advance is required for economic exploitation of both known and unknown reserves of heavy crude oil and oil sands deposits, and
- Canada's balance of payments position would be improved with larger exports of heavy crude oil and greater domestic use of developed resources.

Reasons presented for the separate licensing of condensate and synthetic crude oil were related less to the potential for such materials to supply future energy demands in Canada than to the first point cited above regarding heavy crude oils.

Views of the Board

Having considered evidence presented at the hearing, the Board is of the view that heavy crude oil should be licensed separately and that determination of export volumes of heavy crude oil should be made independently of those of light crude oil and equivalent. The Board for the most part accepts the reasons for separately licensing heavy crude oil that were presented at the hearing.

As regards licensing of condensate and synthetic crude oil, it is the Board's view that these oils should be treated in the same category as light crude oil for determination of surplus volumes. It is the Board's view that condensate should continue to receive priority in access to export markets within the light crude oil and equivalent category. Although marketing problems have not been experienced of sufficient gravity to warrant special treatment for synthetic crude oil, it could also be given special treatment if conditions so require. The Board recognizes that circumstances may arise in which condensate and synthetic crude oil will be surplus to Canadian needs despite what may be shown by any formula restricting allowable exports.

With the above factors in mind the Board made an interim decision to separately license heavy crude oil and to treat condensate and synthetic crude oil within the light crude oil and equivalent category effective 1 January 1976. Appendix O is a copy of the Board's press release dated 23 November 1976 which outlines that decision.

DEFINITION OF HEAVY CRUDE OIL

Views of Submittors

The Board heard evidence from a number of submittors on the question of which heavy crude oil types should be considered for separate licensing. The various submittors differed somewhat as to the desirable definitions of heavy crude oil and as to the inclusion or exclusion of crude oil produced from particular fields.

The most common feature of the submittors' definitions was to classify all crudes with 25° API gravity or less as heavy crudes. Advocacy of such an upper limit was by no means universal: the use of 29° API was also recommended as an upper limit, which would bring more Saskatchewan crudes into the heavy crude oil category. Of particular concern to a number of submittors was treatment of the heavier Midale crudes with API gravities that fall within the 25° – 29° range. These crudes are not used to make asphalt, and according to some submittors have a domestic market outlook substantially different from many other crudes of equal or lower API gravity. For these reasons, many submittors excluded them from definitions of heavy crude oil.

Opinion varied as to whether the light Smiley type crude should be included with the heavier Coleville-type crude when the two are blended. Few submittors addressed this question and strong arguments were not presented to support either point of view.

Submittors were in general agreement that heavy crudes produced from experimental projects and heavy crude areas currently under development should be considered in any determination of heavy crude oil surpluses. Predominant among these new areas were the oil sands deposits in Alberta.

Several submittors asked that any definition of heavy crude oil by the Board should be flexible to permit the inclusion of new heavy crude oil discoveries as they arise. Submittors felt that the probability for new discoveries was very high.

Views of the Board

The Board has considered the evidence concerning the crude oils which should be included in the heavy crude oil category for purposes of separate licensing. With due consideration to producing problems, crude oil quality and marketing characteristics the Board has decided that the definition of heavy crude oil for the purposes of separate licensing should be the same as that hitherto employed by the Board, namely those grades of crude oil given in Table VI-1. In deciding to include the heavier Midale crudes in its definition, the Board recognizes their different usage but is of the view that, when account is taken of the high sulphur content, the domestic market outlook for Midale is not makedly different from that for other crudes of lower gravity.

With respect to the above it may be remarked that the gravity of crude oil export streams comprising the heavy category ranges from about 22° API for Fosterton crude to about 29° API for Midale crude. In several cases light crude oil or condensate is

blended with crude oils with API gravities as low as 12° – 14° API in order to lower the viscosity of the stream for pipeline movement and where transportation practicalities do not warrant segregation. Where it has been industry practice to blend light crude oil and condensate into heavy crude oil streams, such lighter materials also comprise part of the heavy crude oil category. Heavy oil produced from experimental projects in oil sands areas is also considered in the heavy category for licensing purposes.

The Board emphasizes that its definition of heavy crude oil is based on current conditions and is subject to change if marketing or supply considerations so warrant.

Table VI-1

CRUDE OILS INCLUDED IN NEB HEAVY CRUDE OIL CATEGORY
For Purposes of Separate Licensing

- Lloydminster-type blended crude oil delivered to the Interprovincial pipeline system either at Hardisty, Alberta or at Kerrobert, Saskatchewan.
- Wainwright and Viking-Kinsella blended crude oils delivered to the Interprovincial pipeline system at Hardisty, Alberta.
- Chauvin crude oil delivered to the Interprovincial pipeline system through the BP Exploration Canada Limited Chauvin-Hardisty pipeline system.
- Area III medium crude oil in Saskatchewan (Fosterton).
- The Bow River Pipelines Ltd. stream in Alberta, excluding light and medium crude oil normally batched separately.
- Area II blended heavy crude oil in Saskatchewan excluding light crude oil normally batched separately (Smiley-Coleville).
- Area IV medium crude oil in Saskatchewan (Midale-Weyburn).
- Other crude oil with API gravity less than 25° API.

METHOD OF DETERMINING HEAVY CRUDE OIL SURPLUS

Views of Submittors

Several submittors made suggestions as to how the Board might determine an exportable surplus of heavy crude oil, but for the most part these were of a general nature.

Several submittors recommended the use of a formula, similar to or the same as the existing export formula but provided no details of any modifications that might be introduced. Other submittors were of the view that all heavy crude oil surplus to current Canadian requirements for indigenous heavy crude oil should be exported so as to minimize the chances of having shut-in production and at the same time to ensure the protection for domestic requirements. A third recommendation was that the exportation of heavy crude oil should be free of restrictions.

Views of the Board

Having reviewed the evidence and opinions expressed at the hearing, the Board has concluded that the public interest is best served by determining the exportable surplus of heavy crude oil with reference to a protection formula like that previously used for all crude oils. Such a procedure should provide producers with a larger export market than would be the case without separate surplus determination, and at the same time will provide adequate protection for the foreseeable requirements for use of heavy crude oil in Canada.

In reaching this decision the Board recognizes that the supply and demand outlook for heavy crude oil would change if significant volumes of these oils were to be upgraded. The effects of such a change are discussed in Chapter VII.

EXPORTS OF REFINED PETROLEUM PRODUCTS

Views of Submittors

Submittors were generally in agreement that the licensing of crude oil and equivalent and the licensing of refined petroleum products should remain separate. It was felt that the Board should continue to take into account the circumstances surrounding each product export application and that licences should only be issued if the volumes of particular products sought to be exported were found by the Board to be surplus to Canadian needs in regions to which they have timely access.

The Government of Saskatchewan suggested that, should separate licensing procedures be adopted for light and heavy crude oil, the Board consider including products in the export licensing system for light crude oil in cases where such oil was being used to manufacture the products sought to be exported.

Some submittors took the position that Canada should export products in preference to crude oil because such a course would bring benefits, such as those resulting from the upgrading of raw material, from increased employment, and from better balance in product supply and demand.

Several companies pointed out that exports of products surplus to Canadian needs are necessary in order for domestic refineries to balance their operations and to provide products that are required in Canada. Texaco recommended that the Board allow the exportation of refined petroleum products to the extent that excess refining capacity and Canadian oil requirements will permit.

Several submittors suggested that the Board should issue product export licences for periods up to five years in cases where major surpluses could be demonstrated. Texaco pointed out that this would allow term contracts to be arranged on a stable basis. In the opinion of Petrosar, long-term export applications should be the subject of public hearings only where the Board found them necessary because of the filing of objections to the exports.

It was recommended by certain companies that reciprocal import export exchanges of products should be allowed where these could add significantly to refiners' flexibility and contribute to lower costs.

Views of the Board

The Board considers that separate determination of surpluses of crude oil and refined petroleum products should continue and believes that present procedures are adequate to permit this to be done. To attempt closer integration of proceedings over the export licensing of crude oil and of products would, in the Board's view, not only serve little or no purpose, but would both add further complication and reduce the flexibility in regulation that is essential to its efficient and effective conduct.

The Board recognizes that certain benefits may accrue from the issue of long term licences for the exportation of petroleum products and last fall held a public hearing to review certain applications for long term exports, subsequently issuing licences covering periods of up to six years.

With respect to recommendations made on the matter of reciprocal import – export exchanges of refined petroleum products, the Board believes that specific proposals for the conduct of such exchanges are best examined on their merits.

The Board considers the Petrosar proposals to streamline handling of product export applications could be useful in situations where many long term applications are before the Board, but sees no immediate necessity for departure from the practices now in force.

OTHER LICENSING CONSIDERATIONS

The matters of crude oil exchanges and operational constraints were raised at the hearing by submittors. These items and the question of the term of licences for exports of crude oil are discussed below.

Views of Submittors

Crude Oil Exchanges

Several submittors presented opinions on crude oil exchanges. Hudson's Bay Oil and Gas Company Limited ("HBOG") and Koch Oil Co. Ltd. ("Koch") expressed the view that exchanges should be allowed involving the importation of foreign crude oils into Montreal in exchange for the exportation of Canadian oil. Koch stated that such exchanges could provide year-round markets for Canadian heavy crude oil. Pacific noted potential problems of administration and anticipated difficulty in barrel-for-barrel exchanges of Canadian heavy crude oil for light crude oil of U.S. origin. Saskatchewan urged extension of authorized crude oil exchanges. HBOG also urged that exchanges of crude oil for refined petroleum products should be permitted.

Operational Constraints

Very few submittors provided evidence on operational constraints. HBOG mentioned problems with exporting pipelines, specifically regarding the production of crude oil and condensate locationally captive to the Rangeland and Trans Mountain pipeline systems. While acknowledging that the movement of these materials to domestic markets was technically feasible, the company pointed out that it would be costly to provide new facilities, the expense of which would ultimately fall on consumers; on the other hand, the continued export of such crude oil and equivalent would have only minor impact on Canada's energy balance.

Dome Petroleum Limited ("Dome") pointed out that significant volumes of condensate are used as buffers and are entrained in the natural gas liquids ("NGL") mix delivered to the Amoco/Dome separation plant at Sarnia. Disposal of this condensate in segregated form must be made downstream from Sarnia.

Term of Licences

Submittors did not address this topic.

Views of the Board

Crude Oil Exchanges

It is the Board's view that crude oil exchanges, as now taking place, can benefit both Canadian and United States refiners. The first licence to exchange crude oil was approved for August 1976 and by December 1976 the licensed volume of crude oil under exchange had reached 45 Mb/d. Exchanges of crude oil are continuing into 1977. These exchanges are limited to the delivery of Canadian crude oil to U.S. markets in return for crude oil of U.S. domestic origin.

It cannot be excluded that exchange of Canadian crude oil in return for tanker-borne oil delivered to Montreal may in the future be beneficial to Canada. However the NEB Act provides only for the exportation of oil which is surplus, so that Montreal exchanges can be accommodated only if the oil imported into Canada satisfies a Canadian requirement which was previously met by indigenous crude. It follows, therefore, that such exchanges would have to be at the expense of the 250 Mb/d of Western Canadian feedstocks moving to Montreal.

Operational Constraints

The Board observes that regulation must be at once sufficiently flexible to deal with constraints in operations and perceptive enough to appraise them when they are encountered. To date, operational constraints in the licensing of crude oil and equivalent exports have been of such a nature that no special action has been required. With reductions in total exports, this matter will become more important and has been so recognized by U.S. officials concerned with implementation of Canadian import programmes. The Board intends to continue to license exports of crude oil and equivalent where denial of access to foreign markets would in its view cause undue hardship to producers.

Term of Licences

The Board is of the view that, where possible, the term of export licenses for crude oil and equivalent should be lengthened. This would allow a more stable environment for, and greater freedom in, the arranging of both domestic and export crude oil transactions. Especially because short term supply and requirements fluctuations cause complexities with the marketing of condensate, the Board feels, that licensing of light oil should be continued on a monthly basis for the time being.

With respect to heavy crude oil, the situation is somewhat different. In the short term, supply fluctuations are small and requirements although varying seasonally, are predictable with reasonable accuracy. Storage is available to aid in handling excess supply and to meet extra needs when necessary. Sale of heavy crude oil to export markets is now being increased; the incentive for buyers to take increased quantities of heavy crude oil is enhanced under conditions where licence volumes are known for an extended forward period. It is therefore the Board's intention to begin licensing heavy crude oil on a quarterly basis as soon as practicable, consistent with resolution of programming difficulties that may be faced by Canadian refiners. If this quarterly licensing is successfully implemented, consideration will be given to further extension of the licence period.

Protection for Canadian Requirements

In determining the allowable level of crude oil and equivalent exports for 1977 the Board will employ the formula outlined in its October 1974 and September 1975 reports. However, in contrast to previous years, the procedure will be applied separately for heavy crude oil and light crude oil and equivalent.

The procedure used to calculate allowable exports is expressed in the formula as follows:

$$E = [P - (D+C)] \frac{t}{10}$$

Where E is the average annual volume in Mb/d available for export licensing during the year for which the determination is made.

Where P is the forecast annual average potential producibility of crude oil and equivalent in Mb/d during the year for which the determination is made.

Where D is the forecast annual average requirements for Canadian use in Mb/d of indigenous crude oil and equivalent during the year for which the determination is made.

Where C is the forecast total increase that would have occurred in requirements for indigenous crude oil and equivalent in Mb/d if conservation measures since 1972 had not been effective.

Where t is the time during which supply is forecast to exceed Canadian requirements, from 1 January of the year for which the determination is made, expressed to the nearest tenth of a year, and extended to a maximum of ten years.

LIGHT CRUDE OIL AND EQUIVALENT

Using parameters previously determined in this report and illustrated in Figure VII-1, volumes of light crude

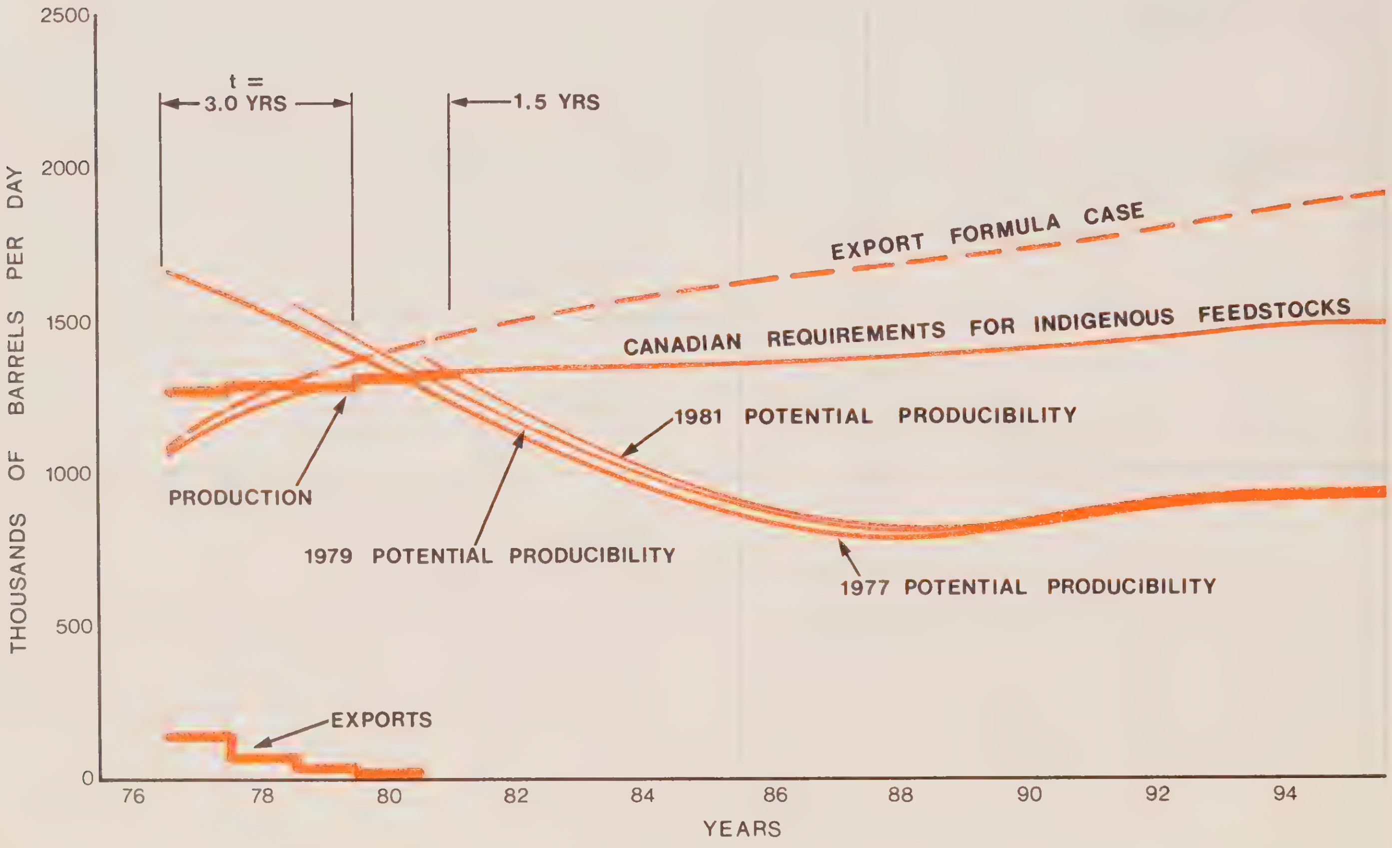


Figure VII-1 CALCULATION OF ALLOWABLE EXPORTS OF LIGHT CRUDE OIL AND EQUIVALENT

oil and equivalent available for licensing in 1977 are:

$$E = [P - (D+C)] \frac{t}{10}$$

$$= [1616 - (1133+25)] \frac{3}{10}$$

$$= 137 \text{ Mb/d}$$

The calculation shown above can be repeated for subsequent years to show the effect the protection procedure might have on exports in the future and how long the supply-demand intersection can be delayed. For each year considered, a new potential producibility projection must be constructed to account for the carry-forward effect of production at rates lower than capacity. The effect of this carry-forward as illustrated in Figure VII-1 ends with a 1981 potential producibility curve, which intersects the Canadian requirements curve in mid-1981, after which time Canadian production of light crude oil and equivalent will no longer be sufficient to meet WOV requirements plus shipments to Montreal.

Using this method, future allowable exports of light crude oil and equivalent are accordingly estimated to be:

Year	Allowable Exports Mb/d
1978	54
1979	20
1980	1
1981	0

As light crude oil exports are reduced to zero, the Board expects that exceptions to its broad policy of phasing-out light crude oil and equivalent exports will likely be necessary. As mentioned in Chapter VI

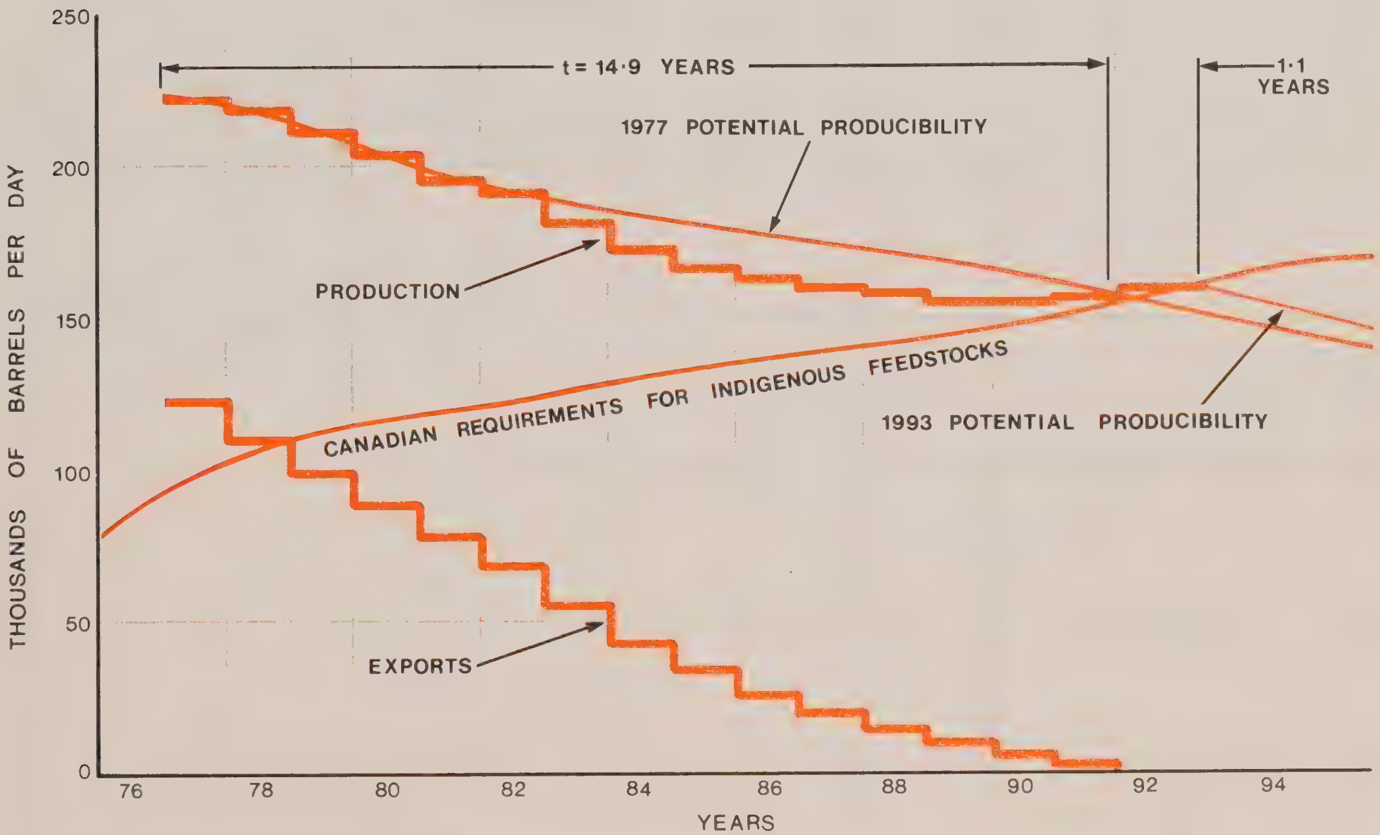


Figure VII-2 **CALCULATION OF ALLOWABLE EXPORTS OF HEAVY CRUDE OIL**

synthetic crude oil and condensate may become available in excess of the calculated surplus volume and operational constraints may also require future light crude oil and equivalent exports.

HEAVY CRUDE OIL

Similar parameters have been determined for heavy crude oil. These parameters are shown in Figure VII-2. Allowable heavy crude oil exports for 1977 are calculated to be:

$$E = [P - (D+C)] \frac{t}{10}$$

$$= [221 - (98+0)] \times 1 \text{ because } t > 10 \text{ years}$$

$$= 123 \text{ Mb/d}$$

When t exceeds 10 years in the Board's export control procedures, the only restriction placed on exports is that feedstock requirements of Canadian refineries must be met first. The remainder of productive capacity is then available for export. Consequently the value 123 Mb/d should only be viewed as an estimate of the volume of heavy crude oil which will be available for export during 1977. The actual value will depend on actual monthly productive capacity and Canadian requirements.

As in the case for light crude oil and equivalent exports, the above calculation can be repeated for subsequent years to estimate long term trends in heavy crude oil exports, as follows:

Year	Allowable Exports Mb/d
1978	110*
1979	99*
1980	88*
1981	77*
1982	68
1983	54
1984	42
1985	32
1986	26

It should be noted that these calculations exclude the effect that a heavy crude oil upgrading facility would have on Canadian requirements for heavy crude oil feedstocks. The Board is aware that studies are now underway to fully evaluate the technical and economic feasibility of building plants to process heavy crude oil into synthetic light crude oil. In application of the export formula to the Board's estimates of supply and requirements for light and heavy crude oil the Board has not adjusted the estimates to account for the effects of upgrading of heavy crude oil. Although there are several ways that upgrading could be accounted for in the separate application of the export formula the net effect of processing heavy crude oil into synthetic light crude oil would be to create additional Canadian requirements for heavy crude oil and additional supply of light crude oil and equivalent. Such a project would therefore "transfer" oil from the heavy crude oil category where there is sufficient supply to meet forecast Canadian requirements for 13 years to the light crude and equivalent category where "t" is only three years.

The Board considers the maximization of Canadian heavy crude oil use in Canada to be in the national interest primarily because in the future Canada will have to rely to a much greater degree on oil sands and heavy crude oil reserves. Upgrading heavy crude oil, whether in existing refineries or in new facilities, will have the effect of shifting Canada's energy reliance from steadily depleting light crude oil reservoirs to the greater potential heavy crude oil deposits.

***t estimated to be greater than 10 years. Exports restricted only by productive capacity and Canadian requirements for heavy crude oil.**

At the present time the Board is unable to speculate as to the outcome of studies now underway. There is some likelihood that upgrading facilities will be constructed and given favourable conditions could perhaps be on stream in the early 1980's. It is the Board's view, however, that several areas of present uncertainty will have to be overcome before investment would proceed:

- federal and provincial taxation policies will have to be clear to investors; term commitments regarding taxation, royalties and prices may have to be made,
- experimental recovery methods will have to be confirmed; pilot studies now underway will require further time to prove effectiveness of enhanced recovery methods and well equipment design, and
- market availability and confidence will have to be evident for companies to develop heavy crude oil producibility in anticipation of assured markets through upgrading.

In response in part to these needs the Board has moved to separately license heavy crude oil and will further evaluate the feasibility of extending the term of heavy crude oil licences.

Possible Range of Supply and Demand Estimates

In October 1974 the Board adopted a policy of restricting crude oil and equivalent exports if forecasts of supply and of requirements indicated a shortage of indigenous supplies to meet Canadian requirements within a ten-year period. This ten-year period was selected having due regard for the accuracy of forecasting and the lead times required to increase producibility through the development of new resources. The intention of this policy was not only to leave some of the currently discovered reserves in the ground for future use, but also to provide a period during which time the planning and development of new supply sources could occur, and during which time policies could be put into place to reduce requirements. In this latter regard it has become the Board's practice to project the supply and requirements forecasts an additional ten years showing the longer term trends which could assist in policy formulation by all levels of government. However, in this second ten-year period the forecasts are subject to greater uncertainty.

This chapter addresses the subject of variability and the effect various assumptions have on the requirements for crude oil and equivalent and the availability of indigenous supplies.

Variability of the various sources of supply was treated in Chapter II, and is presented only in summary fashion in this chapter.

With regard to demand, the concept of price-elasticity is discussed and the effects of various price and economic growth assumptions on energy demand are illustrated.

Finally, the supply and requirements forecasts for total Canada and for "WOV+250" are superimposed and the implications of the long-term variability are discussed.

OVERVIEW OF ALTERNATIVE SUPPLY SCENARIOS

In Chapter II minimum, expected, and maximum producibility cases were developed for each of the oil supply categories which were considered. In estimating the three cases it was noted that geology, technology, government policy, and crude oil price were viewed as important determinants of producibility.

Thus the maximum producibility case assumed that each of the four factors was favourable in encouraging supply. In particular it was felt that favourable geology and technology would be crucial for achievement of this high producibility. Also, however, it was recognized that the dollar returns to the producers would influence supply. These returns would, amongst other things, be a function of the assumed market price of crude oil and government policies concerning royalties and taxation.

The oil prices corresponding to the three supply cases are the same as those shown in Table VIII-4, where price assumptions for energy demand forecasting are summarized.

The total variability for all oil supply categories in the non-frontier areas is shown in Figure VIII-1. The graph shows that crude oil and equivalent supply is likely to remain within a narrow range over the next 8 to 10 years. This is mainly attributable to the lead-time required to bring new supplies into production, particularly supplies from the oil sands or significant additions from enhanced recovery.

Most of the potential for the maximum supply case is estimated to come from oil sands and from enhanced recovery of already discovered reservoirs. In the year 1990, for example, the difference between the minimum and maximum cases is some 580 Mb/d. Of this total, some 68 percent is from oil sands and about 10 percent is from enhanced recovery.

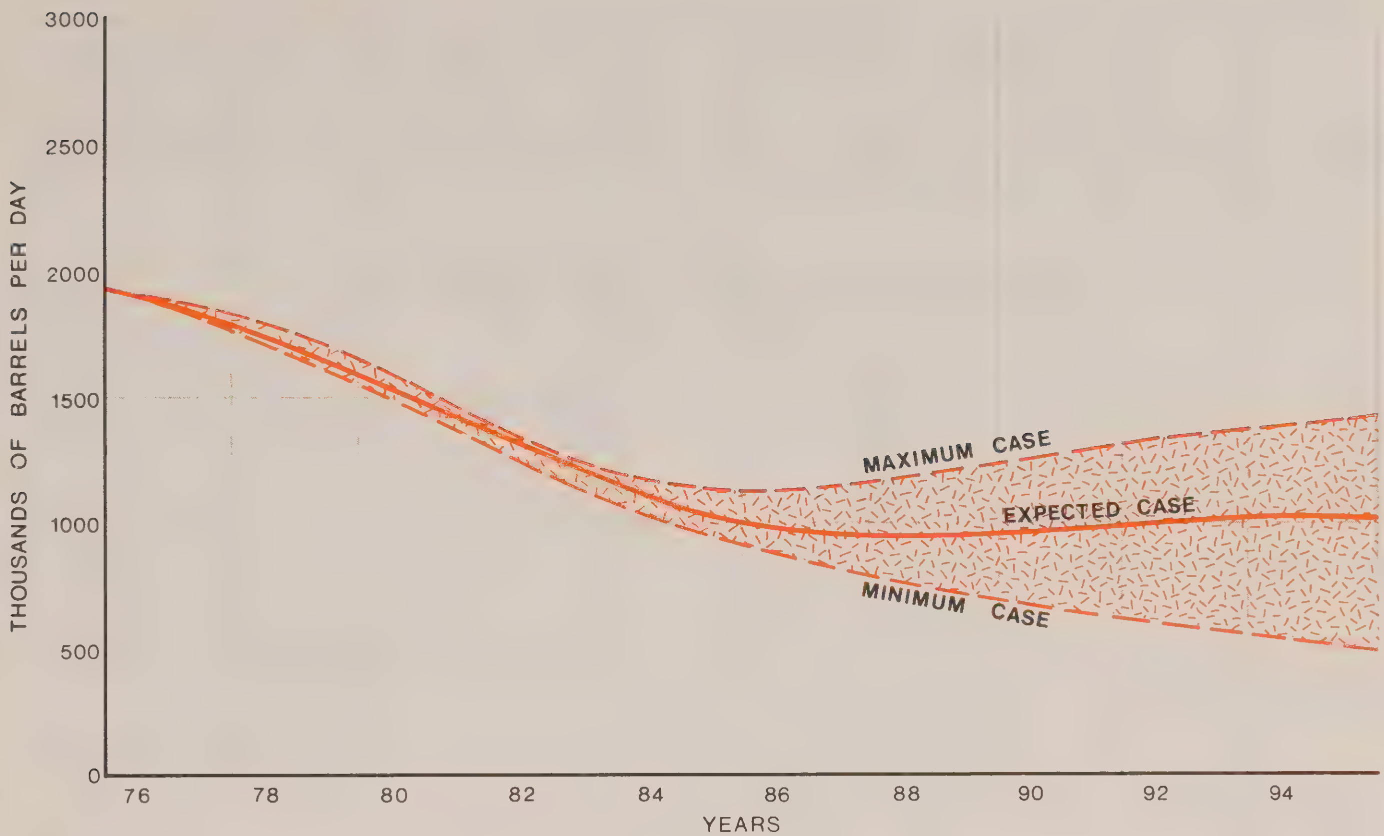


Figure VIII-1 **POTENTIAL PRODUCIBILITY**
Range of NEB Scenarios

OVERVIEW OF ALTERNATIVE DEMAND SCENARIOS

Price-Elasticity of Energy Demand

To calculate the sensitivity of forecast demand with respect to changes in such factors as price, population and income, it is necessary to employ a concept of elasticity. Thus one may speak of the price elasticity of energy demand, the income elasticity of energy demand, the population elasticity of energy demand, and so forth. The measure of elasticity indicates the responsiveness of demand to a change in one of the determining factors. For example, price elasticity measures the proportionate change in energy demand as a result of a change in energy price. While there are many different precise definitions of elasticity, considered below is one of the simplest which is the own-price elasticity of demand.

The own-price elasticity of demand is calculated by dividing the percentage change in demand for a product by the percentage change in its own price. For example, if a 10 percent decline in the price of natural gas induces a 7 percent rise in demand for gas, the own-price elasticity of demand for natural gas would be -0.70.

For purposes of energy demand forecasting it is essential to differentiate between the long-run and the short-run response of demand to changes in price. Thus the complete response which takes time to work itself out, perhaps over a decade, is referred to as the long-run own-price elasticity. The short-run elasticity is often defined as the response which would take place within one year, although the period of response may be specified as desired.

It should be noted that the long-run response considers a time period long enough for changes in energy-using equipment to be made and other resistances to switching between energy fuels to be overcome, whereas the short-run response usually assumes that capital equipment remains unchanged.

The Board has referred to various studies of energy demand and some of the results for estimates of own-price elasticity are displayed, along with the estimates incorporated in the Board's present demand forecasting methodology, in Tables VIII-1 to VIII-3.

Table VIII-1

OWN-PRICE ELASTICITIES* OF DEMAND FOR ENERGY
Residential Sector

Study	Country/ Province	Sector	Total Energy	Oil	Natural Gas	Electricity
NEB (1977)**	Canada	Res	-0.32			
EMR (1975)	Canada	Res	-0.32			
Waverman and Fuss (1975)	Canada	Res		-0.86***		-0.29
Berndt and Watkins (1975)	Ontario	Res-Com			S -0.18, L -0.88	
	B.C.				S -0.17, L -1.15	
Foothills (1974)	Ontario	Res-Com			-0.30	
	B.C.	Res-Com			-0.29	
	Quebec	Res-Com			-0.28	
Watkins (1973)	Ontario	Res-Com			-1.3	
Griffin (1974)	U.S.A.	Res				S - .06, L -0.52
Houthakker, Verleger and Sheehan (1973)	U.S.A.	Res				S - .03, L -0.44
U.S. Project Independence Evaluation Systems Model (1976)	U.S.A.	Res	S -0.13, L -0.49	S -0.75	S -0.72	S -0.51
Wilson (1971)	U.S.A.	Res				-2.0
Mount, Chapman and Tyrrell (1973)	U.S.A.	Res				S -0.14, L -1.2
Anderson (1973)	U.S.A.	Res		-1.58	-2.75	-1.12
Lyman (1973)	U.S.A.	Res				-0.90
Houthakker and Taylor (1970)	U.S.A.	Res				S -0.13, L -1.89
Fisher and Kaysen (1962)	U.S.A.	Res				S -0.15, L 0
Data Resources Inc. (1974)	U.S.A.	Res		-0.13	-0.44	-0.44
Halvorsen (1973)	U.S.A.	Res				-1.33
TEIGA (1976)	Ontario	Res				-0.11
Hyndman (1975)	Canada	Res		-0.62***		-0.12

*Unless otherwise specified, elasticities shown are longrun elasticities.
**Based on model estimated at EMR 1975.
***Refers to price-elasticity for the composite group "petroleum and natural gas".
S Shortrun Elasticity
L Longrun Elasticity

Table VIII-2

OWN-PRICE ELASTICITIES* OF DEMAND FOR ENERGY
Commercial Sector

Study	Country / Province	Total Energy	Oil	Natural Gas	Electricity	Coal
NEB (1977)**	Canada	-0.47				
EMR (1975)	Canada	-0.47				
Waverman and Fuss (1975)	Canada		-1.10	-0.72	-0.31	-2.73
	Atlantic		-0.25	-1.12	-0.31	-2.57
	Quebec		-0.41	-0.64	-0.19	-4.30
	Ontario		-1.51	-0.33	-0.17	-4.27
	Prairies		-2.30***	-0.04	-0.49***	-5.10
	B.C.		-1.35	-0.21	-0.24	-3.88
U.S. Project Independence Evaluation Systems Model (1976)	U.S.A.	S -0.14 L -0.30				
Mount, Chapman and Tyrrell (1973)	U.S.A.				S -0.17 L -1.36	
Lyman (1973)	U.S.A.				-2.10	
Halvorsen (1973)	U.S.A.				-0.94	
TEIGA (1976)	Ontario				-0.80	

*Unless otherwise specified, elasticities shown are longrun elasticities.
**Based on model estimated at EMR 1975.
***1961 values
S Shortrun Elasticity
L Longrun Elasticity

There is also a bibliography contained in Appendix P. As may be seen from the tables of elasticity, there is considerable uncertainty as to the reliability of elasticity estimates. Nonetheless, it may be useful in judging energy demand forecasts to consider the estimates which are contained in these tables. Note that some of these estimates apply to Canada, some to the Provinces, some to the United States, and some to other countries.

In the residential sector the long-run own-price elasticity for total energy incorporated in the Board's present methodology is -0.32 which can be seen to be somewhat lower (i.e. lower in absolute magnitude indicating a lesser responsiveness) than the U.S. Project Independence Evaluation Systems ("PIES") model where an elasticity of -0.49 for the United States is estimated. It can be seen that the estimated long-run elasticity for Canada varies considerably for each of the energy products. Separate estimates for oil products alone are not available. However, for Canada as a whole there are the two estimates in Table VIII-1 of -0.62 and -0.86 for combined petroleum and natural gas. It may also be noted that the long-run elasticity for electricity has been estimated to be significantly lower than "petroleum and natural gas".

In the commercial sector the Board forecast presently uses equations which indicate an historical long-run elasticity of -0.47. The Board's forecast, however, implies a lower elasticity over the forecast period because in this sector the forecasting equation is not structured to maintain a constant own-price elasticity. It may be noted that the PIES long-run estimate is some -0.30 for the United States. Of interest is the

Table VIII-3

OWN-PRICE ELASTICITIES* OF DEMAND FOR ENERGY
Industrial Sector

Study	Country/ Province	Total Energy	Oil	Natural Gas	Electricity	Coal
NEB (1977)**	Canada	-0.29				
EMR (1975)	Canada	-0.59				
Waverman and	Canada	-0.59				
Fuss (1975)	Quebec	-0.58	-1.04	-1.84	-0.28	-4.28
	Ontario	-0.36	-1.27	-0.85	-0.43	-2.49
	Prairies	-0.31	-2.08	-0.74	-0.34	-5.51
	B.C.	-0.68	-1.26	-1.19	-0.27	-6.96
Coombs (1969)	Canada		-1.44	-2.13	-0.71	-4.17
Denny-Pinto (1975)	Canada	-0.59				
Berndt-Watkins (1975)	Alberta	-0.30				
Foothills (1974)	Quebec					
	Ontario			-0.87		
	B.C.					
McRae (1976)	Canada	-0.45	-0.54	-1.08	-0.48	
Griffin (1974)					S L	
	U.S.A.				-.04 -0.51	
U.S. Project Independence Evaluation Systems		S L	S	S	S	S
Model (1976)	U.S.A.	-.13 -.31	-0.70	-0.39	-0.47	-0.56
Berndt and Wood (1975)	U.S.A.	-0.47				
Hudson and Jorgensen (1974)	U.S.A.	-0.50	-0.36	-0.49	-0.31	-.08
Mount Chapman and					S L	
Tyrrell (1973)	U.S.A.				-0.22 -1.82	
Anderson (1973)	U.S.A.				-1.94	
Lyman (1973)	U.S.A.				-1.40	
Data Resources Inc. (1973)	U.S.A.				-0.79	
Erickson, Spann and Ciliano (1973)	U.S.A.		-0.65	-2.53	-1.02	
Kennedy (1974)	Nine		S L			
	Countries		-0.39 -0.76			
Baxter and Rees (1968)					-1.50	
Fisher and Kaysen (1962)	U.S.A.				-1.25	
TEIGA (1976)	Ontario				S L	
					-0.21 -0.34	

**Unless otherwise specified, elasticities shown are longrun elasticities.*

***Based on model estimated at EMR 1975.*

S Shortrun Elasticity

L Longrun Elasticity

Waverman and Fuss estimate for Canada for each of the energy products. It can be seen that the elasticity for oil products is estimated to be substantially higher than that for natural gas which is in turn estimated to be substantially higher than that for electricity. In contrast, however, the 1976 estimate of the Ministry of Treasury, Economics and Intergovernmental Affairs ("TEIGA") for Ontario for electricity in the commercial sector is -0.80.

In the industrial sector the present Board forecast incorporates a long-run own-price elasticity of some -0.29 for total energy demand. This estimate is based principally on the Board's judgement of demand response in the industrial sector and it is lower than the estimates made in the previous studies reported in Table VIII-3 for Canada, but is close to the PIES estimate of -0.31.

Scenarios developed by the Board to examine possible variability in energy demand in Canada over the forecast period are described below. Energy demand estimates for each of six scenarios are discussed. Total primary energy demand and WOV requirements for crude oil and equivalent feedstocks are compared between scenarios. In these scenarios the size of the change in demand arising from a change in the assumed energy price depends on the own-price elasticities incorporated in the Board forecasting methodology.

Assumptions for Alternative Demand Scenarios

In considering possible energy demands the Board has prepared six scenarios of future energy demand and one "Export Formula Case" for the period 1976 to 1995. These scenarios combined two assumptions of economic growth and four price assumptions, as summarized in Table VIII-4.

As noted in Chapter III, Scenario I is considered by the Board to be the expected or most likely case and is referred to elsewhere in this report as simply, the Board's forecast. Scenario I is, however, only one scenario in a range of possibilities. Hence, it is useful to consider the breadth of this possible range and the relationship of the spread to the most important influencing factors.

Scenarios I to III employ an assumption of medium economic growth. The high economic growth assumption employed in Scenarios IV to VI is the same as the medium growth for the period up to 1980, but thereafter it follows economic growth conditions similar to those of the historical period 1960 to 1974. Table III-3 of Chapter III contains a summary of the major assumptions for the medium economic growth case, and the corresponding growth rates over the 1960 to 1974 period.

Table VIII-4

BASIC ASSUMPTIONS FOR NEB ENERGY DEMAND SCENARIOS

Scenario	Economic Growth	International Crude Oil Prices	
I	Medium	Medium:	Constant in Real Terms at 1975 Level
II	Medium	Low:	Constant in Nominal Terms after 1975
III	Medium	High:	Rising in Real Terms at 5 percent per annum after 1975
IV	High	Medium:	Constant in Real Terms at 1975 Level
V	High	Low:	Constant in Nominal Terms after 1975
VI	High	High:	Rising in Real Terms at 5 percent per annum after 1975
Export Formula Case	Medium		Constant in Real Terms at 1972 Level.

With regard to the energy price assumptions, for all scenarios it is assumed that the domestic price of crude oil approaches the world price of crude in 1980, the Toronto city-gate price of natural gas increases to the Btu equivalent refinery gate price of crude oil in 1980, and electricity prices increase in real terms to 1980, remaining constant (in real terms) thereafter.

In Scenario I it is assumed that the world price of crude oil will remain constant in real terms at the 1975 level. Scenario II assumes that the world price of crude oil will remain constant in nominal terms, and hence the domestic crude oil price in real terms declines by approximately 5 percent per year after 1980. In Scenario III the world price of crude oil is assumed to increase in real terms by 5 percent per year after 1975.

Scenarios IV, V and VI are based on the same price assumptions as Scenarios I, II and III respectively.

It would be expected that market shares would change under the different price and growth assumptions of the six scenarios. However in this analysis market shares in each of the scenarios are kept the same as estimated for Scenario I. As a result, it is expected that oil demand may be underestimated to some extent in Scenario II (and Scenario V) but overestimated in Scenario III (and Scenario VI), yielding a range in oil demand which is somewhat narrower than might otherwise be the case. In the shorter term up to 1985, however, this factor is not expected to have a significant effect on the forecast oil demand.

As explained in Chapter III the Export Formula Case was developed for purposes of the oil export formula and it is not considered further in the present comparisons.

Results; Total Primary Energy Demand with Alternative Scenarios

Figure VIII-2 depicts the range in total primary energy demand over the forecast period 1976 to 1995, occurring as a result of the economic growth and price assumptions underlying the six scenarios considered.

Table VIII-5 summarizes projected Canadian total primary energy demands in 1985 and 1995 for the various scenarios considered.

The results for Scenario I, II and III where price varies but not economic growth, indicate a variation in total primary energy demand of 1.8 quads in 1985 and 4.4 quads in 1995. As expected, the lowest price

Table VIII-5

PRIMARY ENERGY DEMAND IN CANADA
NEB Scenarios
(quads)

		Medium Price Scenario I	Low Price Scenario II	High Price Scenario III
Medium Economic Growth	1985	11.0	12.2	10.4
	1995	14.3	16.8	12.4
		Scenario IV	Scenario V	Scenario VI
High Economic Growth	1985	11.3	12.3	10.7
	1995	16.6	18.8	14.4

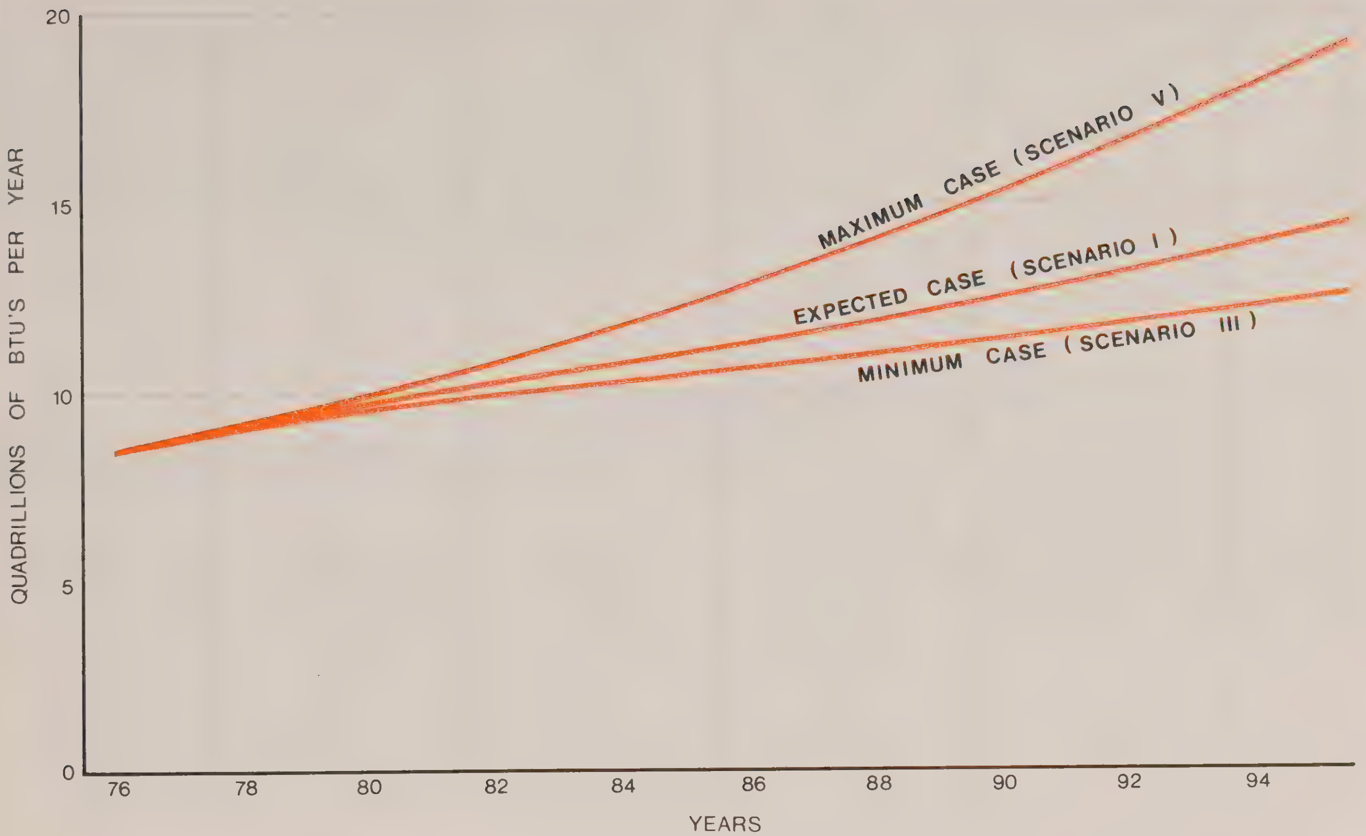


Figure VIII-2. **PRIMARY ENERGY DEMAND**
Range of NEB Scenarios

case, Scenario II, yields the highest level of total primary energy demand, while the highest price case, Scenario III gives the lowest level. These scenarios result in significantly different average annual rates of growth in primary energy demand, with Scenario II averaging 3.7 percent per year over the forecast period and Scenario III averaging only 2.1 percent per year.

A comparison of Scenario IV primary energy demand to that of Scenario I yields information on the sensitivity of primary energy demand to changes in assumed levels of economic activity. By 1985, total primary energy demand in Scenario IV has not changed significantly from Scenario I levels. However, the higher economic growth assumptions of Scenario IV have a pronounced impact on primary energy demand over the longer term. In 1995, for example, total primary energy demand is estimated to be 16.6 quads in Scenario IV, versus 14.3 quads for Scenario I, a difference of 16.1 percent.

In 1995 the possible variation in primary energy demand is from a low of 12.4 quads in Scenario III to 18.8 quads in Scenario V, a difference of 6.4 quads. Average demand growth is substantially higher in Scenario V, averaging 4.5 percent per year over the forecast period, compared to only 2.1 percent for Scenario III.

Results; Crude Feedstock Requirements With Alternative Scenarios

Moving now from total Canadian primary energy demand to that for refined petroleum products and

WOV requirements for crude oil and equivalent, Table VIII-6 shows the WOV refined petroleum product demand for each scenario.

To convert the refined product demand to crude oil and equivalent requirements estimates, the assumed levels of product imports, exports and transfers, and deliveries to refineries of gas plant butanes shown in Appendix L, were applied without change in all cases. Also refinery losses were adjusted to account for the varying product demand levels.

Table VIII-6

REFINED PETROLEUM PRODUCT DEMAND WOV
NEB Scenarios
(Mb/d)

Scenario	1976	1977	1978	1979	1980	1985	1990	1995
I	899.1	949.5	991.8	1020.8	1056.4	1145.7	1234.8	1357.9
II	904.0	963.6	1003.7	1053.2	1112.3	1354.3	1604.4	1820.1
III	896.1	938.9	975.9	1000.3	1025.9	1071.6	1111.5	1169.4
IV	899.1	949.5	991.8	1020.8	1056.4	1160.5	1326.6	1567.7
V	904.0	963.6	1003.7	1053.2	1112.3	1353.7	1649.2	1965.7
VI	896.1	938.9	975.9	1000.3	1025.9	1083.2	1166.3	1290.3

Canadian refinery requirements for indigenous feedstocks corresponding to these scenarios were obtained by converting the WOV refined petroleum product demand to requirements for crude oil and equivalent and then adding an EOV requirement of 250 Mb/d.

Table VIII-7 presents the estimated requirements for indigenous crude oil and equivalent for the six scenarios considered.

Table VIII-7

REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT
NEB Scenarios
(Mb/d)

Scenario	1976	1977	1978	1979	1980	1985	1990	1995
I	1135	1231	1341	1378	1423	1490	1535	1655
II	1140	1246	1354	1411	1482	1709	1914	2141
III	1132	1220	1324	1356	1391	1412	1400	1456
IV	1135	1231	1341	1378	1423	1506	1623	1874
V	1140	1246	1354	1411	1482	1709	1961	2295
VI	1132	1220	1324	1356	1391	1424	1453	1584

Figure VIII-3 depicts the range of the projected requirements for indigenous crude oil and equivalent resulting from the six demand scenarios considered. Scenario III, the lowest demand case, yields an indigenous crude oil and equivalent requirement with an average annual rate of growth of 1.3 percent. Scenario V, the highest demand case, results in an average annual growth of 3.8 percent per year.

SUPPLY DEMAND BALANCES WITH ALTERNATIVE SCENARIOS AND THEIR IMPLICATIONS

The alternative supply and requirements scenarios for indigenous crude oil and equivalent discussed in the previous sections are superimposed in Figure VIII-4.

The supply and requirements curves are for total crude oil and equivalent; no distinction is made for the various grades of crude. The requirements curves include an EOV requirement of 250 Mb/d. This level was attained at the end of 1976 and the Board assumes that, on average, the same volumes will continue to move to Montreal, in accordance with stated government policy. The effect on supply of carry-forward reserves due to shut-in capacity, which is estimated to be less than one year, is not included in this presentation.

From Figure VIII-4 it can be seen that variation in the estimates of supply and requirements between the low and high cases does not significantly change the estimated time at which the producibility of indigenous crude oil and equivalent will no longer be sufficient to meet WOV requirements plus 250 Mb/d for Montreal. This will almost certainly occur between 1981 and 1983.

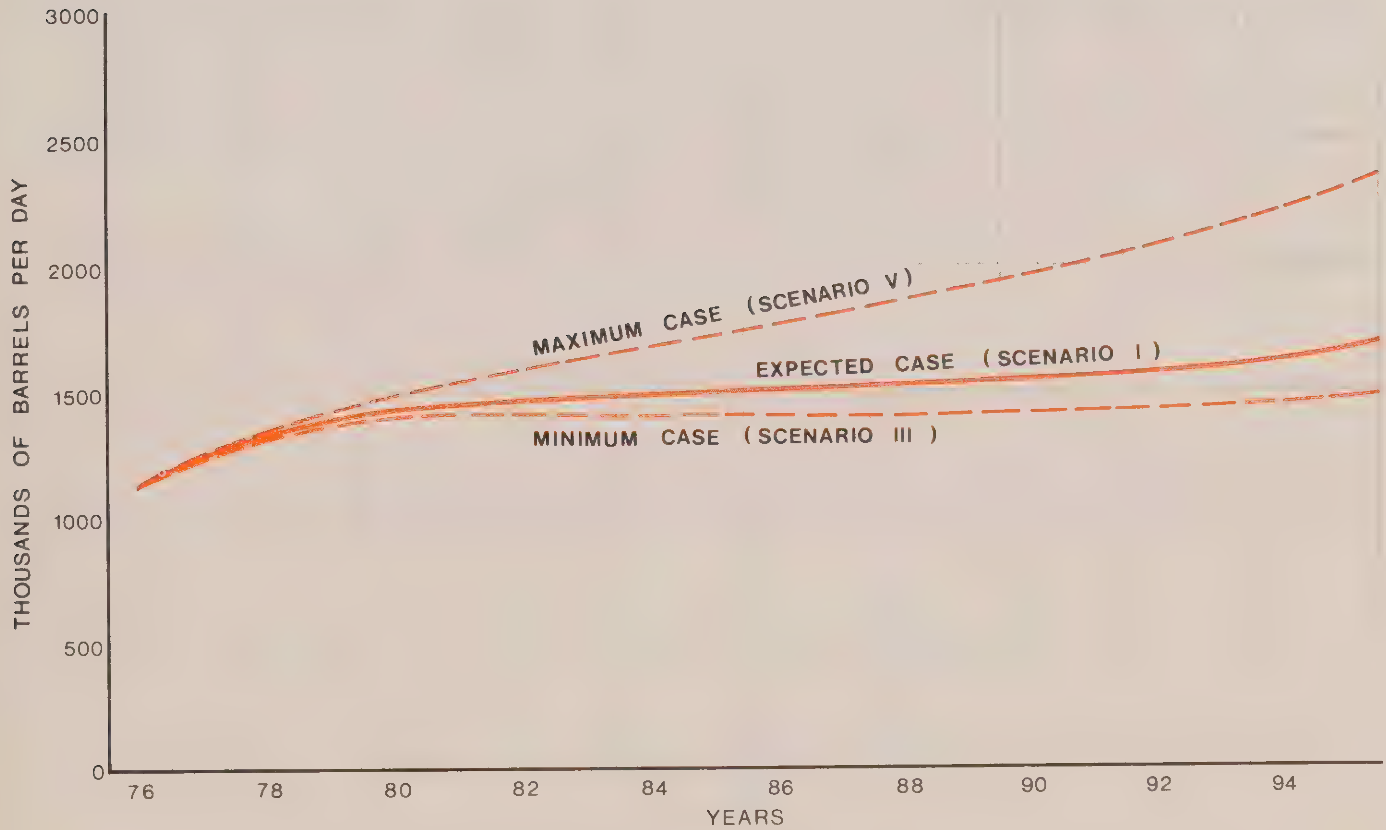


Figure VIII-3. **REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT**
Range of NEB Scenarios

The expected case shows that indigenous oil supply will fall short of requirements by approximately 450 Mb/d in 1985, and this shortfall will increase to around 600 Mb/d in the period 1990 to 1995.

Even in the event that the low requirements and high supply scenarios proved to be true, indigenous oil supply is projected to fall short of requirements by approximately 250 Mb/d in 1985 although the shortfall decreases slowly thereafter. Such a coincidence of supply and requirements presumes the Board's most optimistic view of supply and is based on the assumption of a continuously rising real oil price.

The worst situation considered, the high requirements-low supply case, shows that indigenous supply falls short of requirements by about 800 Mb/d in 1985, and by as much as 1800 Mb/d by 1995. In this case the shortfall expressed as a percentage of requirements would be around 47 percent in 1985 and about 78 percent in 1995. In appraising such a case it should be noted that the low oil price assumption implies that world oil supplies would be abundantly available for import to Canada.

In summary, in any combination of the various scenarios considered, imported crude oil will be required commencing in the early 1980's in the markets now served by indigenous crude. Initially it may be presumed that additional imported crude will be taken into Montreal. Later it seems likely that WOV refineries will need imported oil. Conceivably, the feedstock requirements of refineries in Ontario and Western Canada could both be met by foreign crude. It appears that Canadians must begin to face

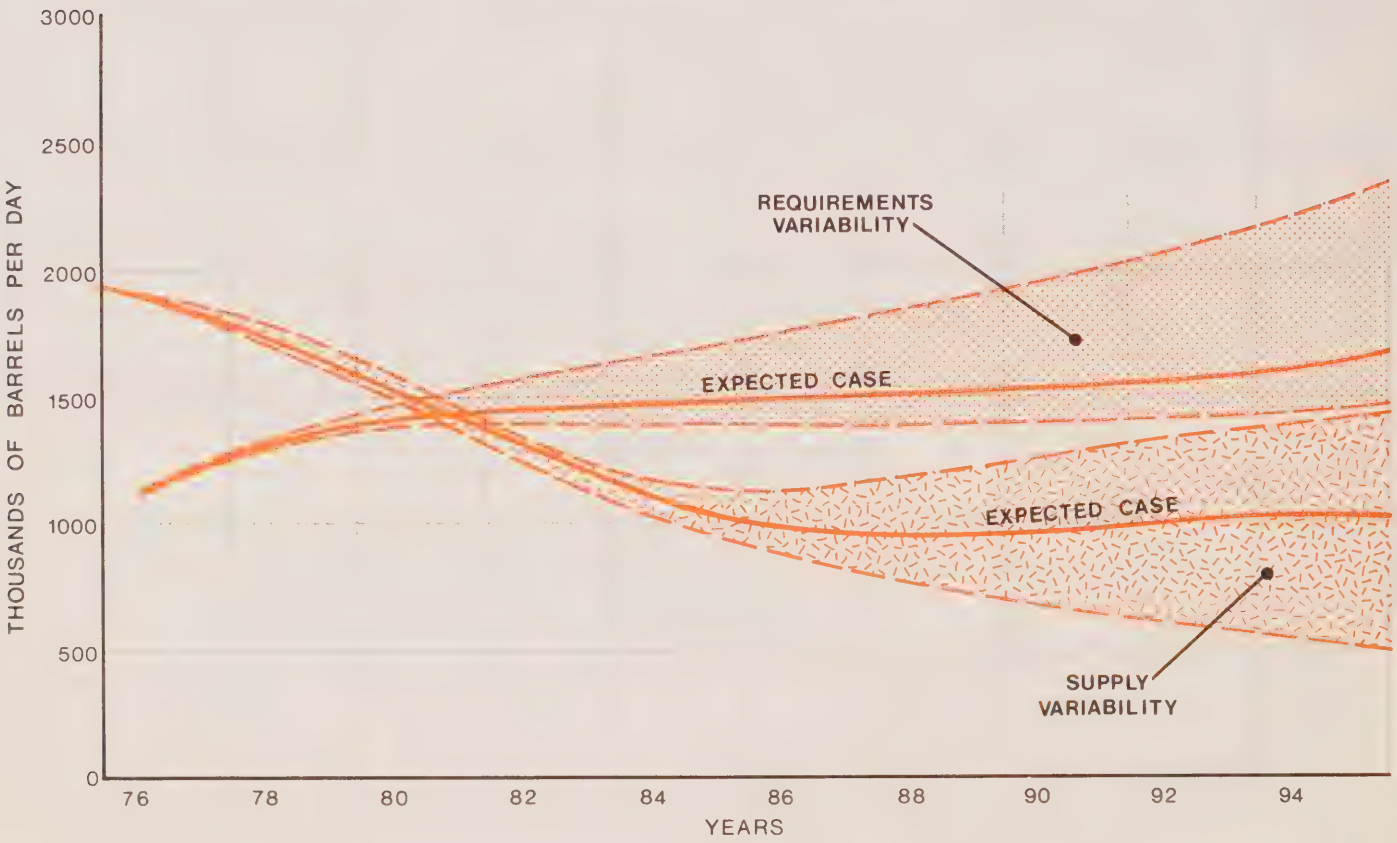


Figure VIII-4. **SUPPLY AND REQUIREMENTS – INDIGENOUS CRUDE OIL AND EQUIVALENT**
Range of NEB Scenarios

up to the prospect of supplying imported crude oil to refineries that have for a quarter of a century used only indigenous feedstocks.

Turning to the crude supply requirements outlook for Canada, as a whole, Figure VIII-5 shows that, for the expected case, production of indigenous crude oil and equivalent will fall short of requirements in Canada by approximately 1150 Mb/d in 1985, increasing to 1300 Mb/d in the period 1990-1995. These shortfalls, which will have to be covered by imports of foreign oil, represent 52 percent of total requirements in 1985 and 55 percent for the period 1990-1995.

In the high supply-low requirements case, the shortfall is projected to be 900 Mb/d in 1985 decreasing to 850 Mb/d by 1995.

In the low supply-high requirements case, imports in 1985 would be 1600 Mb/d, or 62 percent of total requirements, increasing to over 3000 Mb/d, or 83 percent of total requirements by 1995.

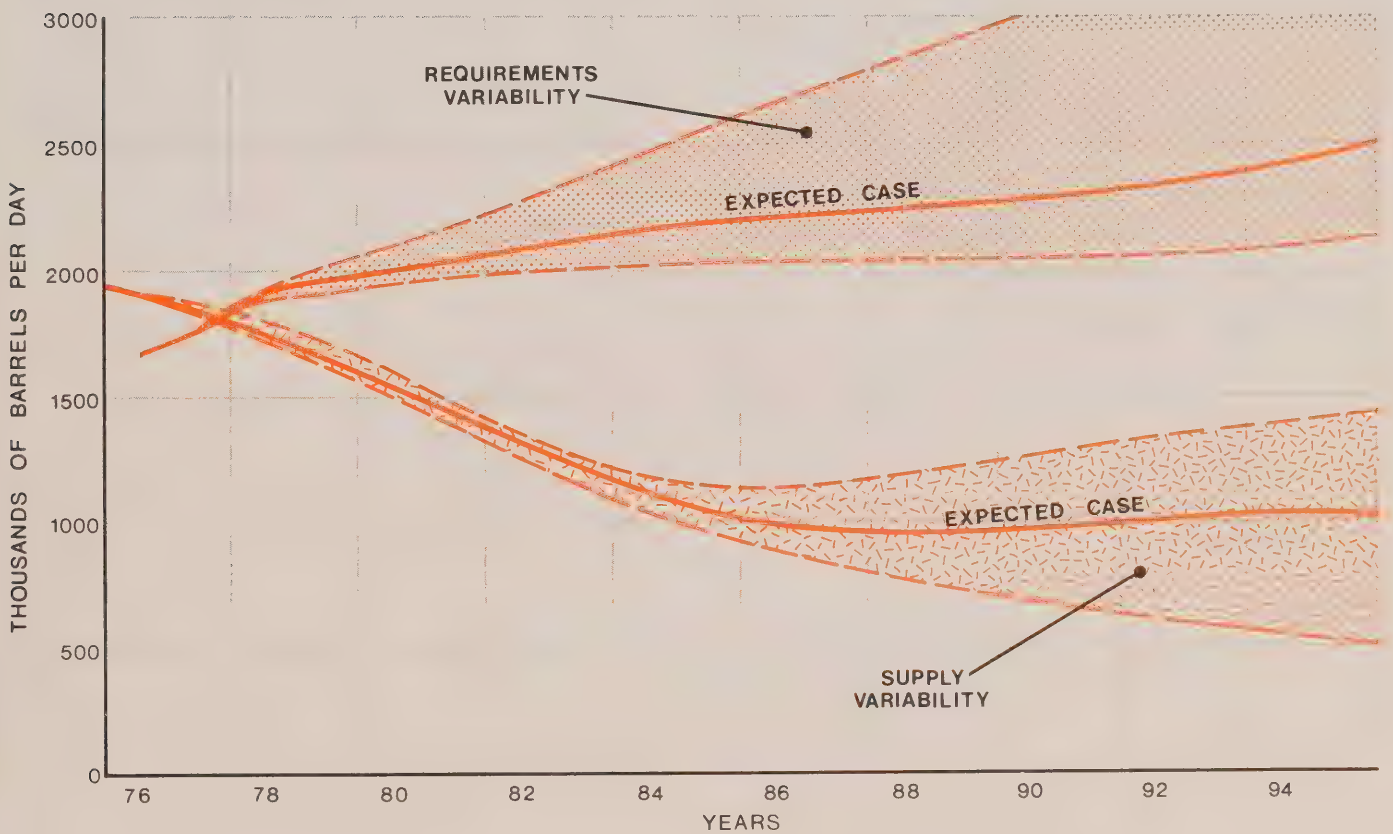


Figure VIII-5. **SUPPLY AND REQUIREMENTS – CRUDE OIL AND EQUIVALENT IN CANADA**
Range of NEB Scenarios

NOTICE OF HEARING

TAKE NOTICE THAT The National Energy Board has varied the times at which the Board will hold its Public Hearing into the potential producibility of Canadian oil, the domestic demand for oil and for indigenous feedstocks, the effects of conservation on Canadian consumption and the surplus of Canadian oil and the need to change the system of licensing crude oil and products exports. By Order No. AO-1-OHR-1-76, the Public Hearing will be held at the following places and times:

Calgary

The Bonavista Room of the Calgary Inn, 320-4th Ave. S.W., Calgary, Alberta on the 19th day of October 1976 at 9:30 a.m. local time.

Ottawa

The National Energy Board Hearing Room, 473 Albert Street, Ottawa, Ontario on the 26th day of October 1976 at 9:30 a.m. local time.

DATED at the City of Ottawa, in the Province of Ontario, this 27th day of May, 1976.

NATIONAL ENERGY BOARD

"Brian H. Whittle"

Brian H. Whittle,
Acting Secretary

NOTICE OF HEARING

TAKE NOTICE THAT The National Energy Board's Public Hearing into the potential producibility of Canadian oil, the domestic demand for oil and for indigenous feedstocks, the effects of conservation on Canadian consumption and the surplus of Canadian oil and the need to change the system of licensing crude oil and products exports, convened by Order No. OHR-1-76 will be held at the following places and times:

Calgary

The Bonavista Room of the Calgary Inn, 320-4th Ave. S.W., Calgary, Alberta on the 5th day of October 1976 at 9.30 a.m. local time.

Ottawa

The National Energy Board Hearing Room, 473 Albert Street, Ottawa, Ontario on the 12th day of October 1976 at 9.30 a.m. local time.

Interested parties may obtain a copy of the Hearing Order and an Outline for Submissions by writing to the Secretary of the Board at the Trebla Building, 473 Albert Street, Ottawa, Ontario, K1A 0E5 or by telephoning 613-992-5506.

DATED at the City of Ottawa, in the Province of Ontario, this 19th day of February, 1976.

NATIONAL ENERGY BOARD

"Brian H. Whittle"

Brian H. Whittle,
Acting Secretary

OUTLINE FOR SUBMISSIONS

Submittors are encouraged to use the following outline in the preparation of material for submission to the 1976 hearing into the matter of the producibility of Canadian oil, the domestic demand for feedstocks, the effects of conservation on Canadian consumption, the surplus of Canadian oil and the need to change the licensing system of crude oil exports. The supply and demand categories outlined are again based on the principles and procedures suggested at the Board's 1974 hearing in the matter of the exportation of oil which also formed the basis for the 1975 hearing on Canadian oil supply and requirements.

For further information on Supply, questions should be directed to K. Vollman, Research Division, Engineering Branch, National Energy Board. The telephone number is (613) 996-2344.

Requests for additional information relating to Demand should be directed to B. Wells, Oil Policy Branch (613) 996-1904 or, A. Siminowski, Economics Branch (613) 996-6049, National Energy Board.

I. SUPPLY

Forecasts with respect to supply should present estimates of the average annual ability to produce Canadian crude oil and equivalent, unrestricted by demand, by province or territory for the period 1976-1995 for each of the following categories:

(i) conventional crude oil from

- (a) established reserves at 1 January, 1976
- (b) reserves additions to existing reservoirs
- (c) new discoveries in existing producing regions;

(ii) pentanes plus from

- (a) established reserves at 1 January, 1976
- (b) reserves additions to existing reservoirs
- (c) new discoveries in existing producing regions;

(iii) oil recoverable from oil sands by

- (a) surface mining
- (b) in situ techniques; and

(iv) frontier crude oil and equivalent.

Submissions should outline the technique used to forecast each supply category and all major assumptions should be stated. Grouping of categories is discouraged since it makes comparison of forecasts difficult.

In the case of i (a) above the Board suggests that a pool by pool forecasting technique be used by those submittors who have access to the requisite data base. In order to assist the Board in assessing the supply-demand balance for various types of crude, it is suggested that submittors present sub-totals by oil grade using the following sub-categories:

- light and medium crude
- Lloydminster type crude
- other heavy crude

It is the Board's intention to differentiate between these sub-categories by using pipeline batches based on the list of pipeline systems and producing pools attached as Appendix 1. The sub-categories are defined as follows:

Lloydminster crude is crude normally transported by the Husky Pipeline Ltd. — Lloydminster Area in Alberta (Wainwright crude excluded) and crude normally transported by the Husky Pipeline Ltd. and Murphy Oil Company Ltd. in Saskatchewan. Heavy crude oil produced from the Cold Lake oil sands deposit and used as a refinery feedstock without being processed in an upgrading facility is also included in this sub-category.

Other Heavy crude is Wainwright crude and crude oil or heavy crude batches normally transported by one of the following pipeline systems:

Bow River Pipe Lines Ltd. — Heavy batch	(Alberta)
BPOG Operations Ltd.	(Alberta)
Heavy crude shipped in trucks and tankcars	(Alberta)
Bow River Pipe Lines Ltd.	(Saskatchewan)
South Saskatchewan Pipe Line Company	(Saskatchewan)
Westspur Pipe Line Company — Midale medium	(Saskatchewan)

Light and Medium crude is all conventional crude production not defined above.

The Board intends to publish an oil producibility forecast by grade of oil based on a forecast by feeder pipeline system similar to the forecast published in Appendix D of the 1975 Oil Supply and Requirements report. This forecast will be

based on evidence received at this hearing, including evidence on individual pools. A list of pools which the Board intends to study is attached as Appendix 1. The Board expects that companies which are operators or major participants in any of the pools listed in Appendix 1 will submit a producibility forecast for these pools. While this list is intended to serve as a guideline, submittors may wish to provide data on alternate or additional pools where they feel this would improve the accuracy of the forecast.

The Board requests that all pool producibility data be submitted in the format illustrated in Appendix 2. However, it is not the Board's intention to limit data to those requested in Appendix 2. Submittors are encouraged to submit any additional data, such as decline curve analyses, economic limits, etc., which they feel are pertinent to the matter of determining supply.

The following guidance is offered to assist submittors in completing Appendix 2.

Section A

Normally, field pools will be identified by completing the spaces marked "FIELD" and "POOL". The space "UNIT" will be left blank except for

(i) cases listed in Appendix 1 where a unit, voluntary unit, or non-unit grouping of wells is to be studied; and

(ii) cases in which the submittor may wish to provide a single producibility forecast for a pool, but may wish to provide reservoir data (eg. recovery factors) on a unit basis. In these cases the submittor would use as many forms as required for the reservoir data, with only the first form in the series containing a pool producibility forecast.

Section B

In cases where the submittor has adopted "proven" and "probable" reserves definitions, the producibility forecast should be in respect of proven reserves. Future producibility should include production expected in respect of development programs which are contemplated with a high degree of certainty. Producibility is defined as the estimated average annual ability to produce, unrestricted by demand but restricted by reservoir performance, well density and well capacity, oil sands mining capacity and field processing capacity, that could be achieved on 90 days' notice.

Section C

Reservoir data should also relate to established or proven reserves. The Board is requesting these data to form a basis for comparing different producibility forecasts.

Section D

Information provided in Section D will assist the Board in assessing the potential for reserves additions from existing pools through infill drilling or improved recovery. Projected reserves additions should be based on the submittor's view of what will be technologically feasible under present and anticipated economic conditions. Submittors are encouraged to elaborate and the limited space under Section D is not intended to restrict or discourage such elaborations.

With respect to i(b) and i(c), (page 2, reserves additions and new discoveries) it is the intention of the Board to use this information to prepare a producibility forecast from reserves additions for each of the crude oil sub-categories: Lloydminster type crude, Other Heavy crude, Light and Medium type crude. Section D of Appendix 2 could be helpful in this regard but is not sufficient. Submittors with a special interest in one or more of the sub-categories are therefore requested to submit a reserves additions schedule for one or more of the crude oil sub-categories. Submittors that do not wish to submit a reserves additions schedule by sub-category are encouraged nevertheless to submit a total reserves additions forecast.

With respect to ii(a) (page 2, pentanes plus supply from established reserves) the Board suggests that a forecasting technique based on individual gas processing plants be used by those submittors who have access to the requisite data.

The Board intends to base its forecast of pentanes plus supply on the evidence received including evidence on individual gas processing plants. A list of plants which the Board intends to review in detail is attached as Appendix 3.

The Board expects that companies which are operators of or major participants in any of these plants will submit a production forecast. This list is intended as a guide and submittors may wish to provide data on plants not listed in Appendix 3.

The Board requests that all plant production data be submitted in a format illustrated in Appendix 4. In order to

clarify some of the assumptions inherent in a production forecast for pentanes plus the Board would appreciate receiving supporting data such as: product yields as a function of pool reservoir pressure, anticipated production rates and product yields in cycling schemes. Operators of a plant producing NGL mix should provide a forecast of NGL mix production accompanied by a percentage breakdown by component of total mix.

II. DEMAND

The forecast of refinery feedstock requirements to satisfy Canadian demand for petroleum products should be based on projections of total market sales of refined petroleum products, taking into account the total energy outlook and interfuel competition. Although the Board does not intend to conduct an in-depth study of the supply/demand of other energy forms for the purposes of this hearing, submittors are requested to provide sufficient information on the assumptions regarding utilization of the other energy forms so that comparative evaluations of the submitted oil forecasts can be made.

The forecasts of total market sales of refined petroleum products must be adjusted for industry use and loss, exports and imports. Regional forecasts must also be adjusted for product transfers. The separate contribution of butanes of gas plant origin to oil product supply has also to be distinguished, together with the proportion of foreign origin oil in total refinery runs.

All forecasts should be expressed in thousands of barrels per day and should be accompanied by actual data for one year or more. All major assumptions should be clearly described, especially those regarding relative prices and the competitive situation of oil and other energy forms in various markets. Submittors should provide a quantitative reconciliation of the respective forecasts of product sales and feedstock requirements in the format illustrated in Appendix 5.

Product Sales

The suggested level of detail for estimates of total market product sales is as follows: Forecast Period — Demand for years 1976, 1977, 1978, 1979, 1980, 1985, 1990, 1995.

Geographic Areas

Atlantic

Quebec

Ontario

Manitoba

Saskatchewan

Alberta

British Columbia

Yukon and Northwest Territories

Total Canada

Ottawa Valley (these estimates should also be included in the total Ontario forecast)

East of the Ottawa Valley line

West of the Ottawa Valley line.

Product Categories

Motor Gasolines	As described in Statistics Canada, Publication 45-208
Light Fuel Oil, Kerosene, Stove Oil	
Diesel Fuel Oil	
Heavy Fuel Oil	

Petrochemical Feedstock — those products intended for petrochemical processing that are manufactured in oil refining operations (including gases and petrochemical naphtha).

Other products

Total products

Feedstock Requirements

The suggested level of detail for demand estimates of crude oil and equivalent is as follows:

Forecast Period — Demand for years 1976, 1977, 1978, 1979, 1980, 1985, 1990, 1995.

Geographic Areas — East of the Ottawa Valley line (including Montreal requirements for domestic feedstocks)

	West of the Ottawa Valley line	
	Total Canada	
Feedstock origin — and type	Canadian	— Lloydminster type (including Cold Lake production) — Other Heavy — Pentanes Plus segregated — Synthetic — Other light & Medium
	Foreign	

To assist in the preparation of a supply demand balance for various types of crude, submittors providing estimates on Canadian feedstock requirements are requested to estimate the industry requirement West of the Ottawa Valley line plus Montreal requirements for Lloydminster type (including Cold Lake production), Other Heavy crudes, segregated pentanes plus, synthetic crude and other light and medium crudes.

The "Other Heavy crudes" category is consistent with that shown on the supply section on page 3 and includes the following streams:

Bow River Pipe Line Ltd: Heavy Alberta

Wainwright

Chauvin

Fosterton — Dollard

Smiley — Coleville Blend

Midale — Weyburn

Conservation

Submittors are requested to provide opinions and, if possible, estimates to assist the Board in identifying and quantifying reductions in Canadian oil demand resulting from conservation measures. 'Conservation measures' embrace:

- those programs designed specifically to reduce petroleum demand,
- those policies, whether general or specific, which may have a bearing on the consumption, conservation and price of any or all energy forms, and which may have a direct or indirect impact on petroleum demand.

III. OPERATION OF EXPORT LICENSING SYSTEMS

Submittors are requested to provide opinions to assist the Board in identifying any changes considered desirable in respect of the system for licensing crude oil and product exports.

NATIONAL ENERGY BOARD
LIST OF POOLS AND POOL GROUPINGS
FOR CRUDE OIL PRODUCIBILITY FORECAST

NORTHWEST TERRITORIES

FIELD	POOL	UNIT
I. NORMAN WELLS		
Norman Wells	All	–

BRITISH COLUMBIA

FIELD	POOL	UNIT
I. BLUEBERRY-TAYLOR PIPELINES		
Aitken Creek	Gething	–
Blueberry	Debolt	–
Inga	Inga	–
Other	–	–
II. TRANS-PRAIRIE PIPELINES LTD., - BEATTON RIVER - TAYLOR		
Beatton River	Halfway	–
Beatton River West	Bluesky-Gething	–
Crush	Halfway	–
Currant	Halfway	–
Milligan Creek	Halfway	–
Peejay	Halfway	–
Weasel	Halfway	–
Wildmint	Halfway	–
Other	–	–
III. TRANS-PRAIRIE PIPELINES LTD., - BOUNDARY LAKE - TAYLOR		
Boundary Lake Unit No. 1	Boundary Lake	–
Boundary Lake Unit No. 2	Boundary Lake	–
Other	–	–

ALBERTA

FIELD	POOL	UNIT
I. BOW RIVER PIPE LINES LTD., LIGHT AND MEDIUM		
Provost	Viking CAK	–
Other	–	–
II. BOW RIVER PIPE LINES LTD., HEAVY		
Bantry	Mannville A	–
Countess	Upper Mannville D	–
Countess	Upper Mannville H	–
Grand Forks	Lower Mannville D	–
Hays	Lower Mannville A	–
Lathom	Upper Mannville A	–
Taber	Mannville D	–
Taber South	Mannville B	–
Other	–	–
III. BPOG OPERATIONS LTD.		
Chauvin	Mannville A	–
Chauvin South	Sparky A&B	–
Chauvin South	Sparky H	–
Chauvin South	Lloydminster D	–
Other	–	–
IV. CANADIAN INDUSTRIAL GAS AND OIL LTD.		
Joarcam	Viking	–
V. CREMONA PIPELINE		
Crossfield	Cardium A	–
Harmattan East	Rundle	–
Harmattan Elkton	Rundle C	–
Other	–	–
VI. FEDERATED PIPE LINES LTD.		
Carson Creek North	Beaverhill Lake A	–
Carson Creek North	Beaverhill Lake B	–
Judy Creek	Beaverhill Lake A	–
Judy Creek	Beaverhill Lake B	–
Swan Hills	Beaverhill Lake A&B	–
Swan Hills	Beaverhill Lake C	–
Swan Hills South	Beaverhill Lake A&B	–
Virginia Hills	Beaverhill Lake	–
Other	–	–
VII. GIBSON PETROLEUM COMPANY LIMITED		
Bellshill Lake	Blairmore	–
Thompson Lake	Blairmore	–
VIII. GULF ALBERTA PIPE LINE		
Clive	D-2A	–
Clive	D-3A	–

ALBERTA (Continued)

FIELD	POOL	UNIT
Drumheller	D-2B	–
Duhamel	D-2A	–
Duhamel	D-3B	–
Erskine	D-3	–
Fenn Big Valley	D-2A	–
Hussar	Glauconitic A	–
Joffre	D-2	–
Stettler	D-2A	–
Stettler	D-3A	–
West Drumheller	D-2A	–
Other	–	–

IX. HUSKY PIPELINE LTD. - LLOYDMINSTER AREA

Lloydminster	Spky C and GP A	–
Lloydminster	Spky and GP C	–
Viking Kinsella	Wainwright B	–
Wainwright	Wainwright	–
Other	–	–

X. THE IMPERIAL PIPE LINE COMPANY, LIMITED - ELLERSLIE

Acheson	D-3A	–
Golden Spike	D-3A	–
Other	–	–

XI. THE IMPERIAL PIPE LINE COMPANY, LIMITED - EXCELSIOR

Excelsior	D-2	–
Fairydell-Bon Accord	D-3A	–
Other	–	–

XII. THE IMPERIAL PIPE LINE COMPANY, LIMITED - LEDUC

Leduc-Woodbend	D-2A	–
Leduc-Woodbend	D-3A	–
Other	–	–

XIII. THE IMPERIAL PIPE LINE COMPANY, LIMITED - REDWATER

Redwater	D-3	–

XIV. MURPHY MILK RIVER PIPE LINE

Coutts	Total	–
Manyberries	Total	–
Red Coulee	Total	–
Other	–	–

XV. PEACE RIVER OIL PIPE LINE CO. LTD.

Goose River	Beaverhill Lake A	–
Kaybob	Beaverhill Lake A	–
Kaybob South	Triassic A	–
Nipisi	Gilwood A	–
Simonette	D-3	–
Snipe Lake	Beaverhill Lake	–
Sturgeon Lake	D-3	–
Sturgeon Lake South	D-3	–
Utikuma	KR Sand A	–
Other	–	–

XVI. PEMBINA PIPE LINE LTD.

Pembina	Cardium	–
Pembina	Keystone Belly River B	–
Willesden Green	Cardium A	–
Other	–	–

XVII. RAINBOW PIPE LINE COMPANY, LTD.

Mitsue	Gilwood A	–
Nipisi	Gilwood A	–
Rainbow	KR A	–
Rainbow	KR B	–
Rainbow	KR F	–
Rainbow	KR AA	–
Rainbow South	KR A	–
Rainbow South	KR B	–
Rainbow South	KR E	–
Virgo	Total	–
Zama	Total	–
Other	–	–

XVIII. RANGELAND PIPE LINE COMPANY LIMITED

Ferrier	Cardium E	–
Gilby	Jurassic B	–
Gilby	Viking A	–
Innisfail	D-3	–
Joffre	D-2	–

Medicine River	Glauconitic A	—
Medicine River	Jurassic A	—
Medicine River	Jurassic D	—
Sundre	Rundle A	—
Willesden Green	Cardium A	—
Other	—	—

XIX. TEXACO EXPLORATION CANADA LTD.

Bonnie Glen	D-3A	—
Glen Park	D-3A	—
Westerose	D-3	—
Wizard Lake	D-3A	—
Other	—	—

XX. TRANS-PRAIRIE PIPELINES LTD.: BOUNDARY LAKE SOUTH

Boundary Lake South	Triassic E	—
Other	—	—

XXI. TWINING PIPELINE DIVISION

Twinning	Run. A & LM A	—
Twining North	Rundle	—

XXII. VALLEY PIPE LINE

Turner Valley	Rundle	—

XXIII. TRUCK AND TANK CAR

Cessford	Total	—
Other Heavy	—	—
Light and Medium	Total	—

SASKATCHEWAN (Continued)

FIELD	**POOL**	**UNIT**
I. HUSKY PIPELINE LTD. AND MURPHY OIL COMPANY LTD.		
Aberfeldy	Sparky Sand	Aberfeldy
South Aberfeldy	Sparky Sand	South Aberfeldy Vol.
Dulwich	Sparky Sand	—
Epping	Sparky & GP Sand	Non-Unit
Epping South	Sparky & GP Sand	Unit No. 1
Epping Southwest	Sparky Sand	Vol. Unit No. 1
Furness	Sparky Sand	—
Golden Lake North	Waseca & Sparky Sand	Vol. Unit
Golden Lake North	Waseca Sand	Non-Unit
Golden Lake South	Sparky Sand	—
Golden Lake South	Waseca Sand	—
Gully Lake	Waseca Sand	Vol. Unit No. 1
Gully Lake	Waseca Sand	Non-Unit
Lashburn	Waseca Sand	Vol. Unit
Lone Rock	Sparky Sand	—
Other	—	—
II. BOW RIVER PIPE LINES LTD.		
Coleville	Bakken Sand	—
Dodsland	Viking Sand	Gleneath Unit
Dodsland	Viking Sand	Eagle Lake Viking Vol. Unit
North Hoosier	Bakken Sand	North Hoosier - Bakken Sand Vol. Unit
North Hoosier	Basal Blairmore Sand	North Hoosier Sand Blairmore Vol. Unit
Smiley Dewar	Viking	—
Other	—	—
III. SOUTH SASKATCHEWAN PIPE LINE COMPANY		
Battrum	Roseray Sand	Battrum Unit No. 1
Cantuar	Cantuar Sand	Cantuar Unit
Dollard	Upper Shaunavon	Dollard Unit
Fosterton	Roseray Sand	Fosterton Main Unit
Gull Lake North	Upper Shaunavon	Gull Lake Unit
Instow	Upper Shaunavon	Instow Unit
Main Success	Roseray Sand	Success Main Unit
North Premier	Roseray Sand	North Premier Unit No. 3
Rapdan	Upper Shaunavon	Rapdan Unit
South Success	Roseray Sand	Success Unit
Suffield	Upper Shaunavon	Unit No. 2
Verlo	Roseray Sand	Unit
Other	—	—

IV. WESTSPUR PIPE LINE COMPANY - MIDALE MEDIUM

Benson	Midale	Unit
Flat Lake	Ratcliffe	Vol. Unit No. 1
Innes	Frobisher	–
Lost Horse Hill	Frobisher-Alida	Vol. Unit No. 1
Midale	Central Midale	Unit
Midale	Central Midale	Non-Unit
Sherwood	Frobisher	–
Viewfield	Frobisher	–
Weyburn	Midale	Unit
Weyburn	Midale	Non-Unit
Other	–	–

V. WESTSPUR PIPE LINE COMPANY - S.E. SASKATCH-EWAN LIGHT

Alida East	Alida	Unit
Carnduff	Midale	East Unit
Elmore	Frobisher	–
Ingoldsby	Frobisher-Alida	Vol. Unit
Kenosee	Tilston	Vol. Unit
Parkman	Tilston-Souris Valley	–
Queensdale East	Frobisher-Alida	Non-Unit
Rosebank	Frobisher-Alida	Vol. Unit No. 1
Steelman	Midale	Unit 1A
Steelman	Midale	Unit II
Steelman	Midale	Unit IV
Steelman	Midale	Unit VI
Willmar	Frobisher-Alida	Non-Unit
Workman	Frobisher	Vol. Unit No. 1
Other	–	–

MANITOBA

FIELD	POOL	UNIT
I. TRANS-PRAIRIE PIPELINES LTD.		
Daly	Mississippian	–
Routledge	Mississippian	–
N. Virden Scallion	Mississippian	–
Virden-Roselea	Mississippian	–
Other	–	–

ONTARIO

FIELD	POOL	UNIT
I. ONTARIO		
Ontario	All	–

A. NATIONAL ENERGY BOARD CRUDE OIL PRODUCIBILITY FORECAST

FIELD

POOL

UNIT:

SUBMITTOR

DATE:

B. PRODUCIBILITY FORECAST

From

Established Reserves at 1-1-76

YEAR	BARRELS PER DAY
1976	....
1977	....
1978	....
1979	....
1980	....
1981	....
1982	....
1983	....
1984	....
1985	....
1986	....
1987	....
1988	....
1989	....
1990	....
1991	....
1992	....
1993	....
1994	....
1995	....

C. OIL RESERVOIR DATA

For

Established Reserves at 1-1-76

Area, acres	....
Average pay, ft	....
Rock volume, acre-ft	....
Porosity, %	....
Connate water, %	....
Shrinkage, %	....
Initial oil in place, Mstb	....
Hor, permeability, md	....
Vert. permeability, md	....
Pressure-datum, ft. ss.	....
Initial pressure, psia	....
Initial oil viscosity, cp	....
Current pressure, psia	....
Current oil viscosity, cp	....
Primary recovery, %	....
Improved recovery, %	....
Improved recovery mechanism	....
Total recoverable oil, Mstb	....
Cumulative oil production to 1-1-76, Mstb	....

D. POTENTIAL RESERVES ADDITIONS

DRILLING POTENTIAL

No. of wells .... Recoverable Oil, Mstb ....

Comments ....

IMPROVED RECOVERY POTENTIAL

Method .... Recoverable Oil, Mstb ....

Comments ....

Name or Field	Location	Operator
Bonnie Glen	SW17-47-27W4	Texaco Exploration Canada Ltd.*
Brazeau River	12-46-14W5	Hudson's Bay Oil and Gas Co. Ltd.
Caroline	SW20-34-4W5	Hudson's Bay Oil and Gas Co. Ltd.
Carstairs-Crossfield	6-3-30-2W5	Home Oil Company Ltd.
Cochrane	16-26-4W5	Alberta Natural Gas Co. Ltd. (straddle plant)
Crossfield	10-2-26-29W4	Petrogas Processing Ltd.
Dunvegan	15-3-81-4W6	Anderson Exploration Ltd.
Edson	SW11-53-18W5	Hudson's Bay Oil and Gas Co. Ltd.
Ellerslie	4-51-24W4	Edmonton Liquid Gas Ltd. (straddle plant)
Empress	12-20-1W4	Dome Petroleum Ltd. (straddle plant)
Empress	11-20-1W4	Pacific Petroleums Ltd. (straddle plant)
Ferrier	2-6-41-7W5	Amerada Minerals Corp. of Canada Ltd.
Fort Saskatchewan Fractionation Plant	1-20-39-7W5	Chevron Standard Ltd.
Gilby	15-22-40-3W5	Texaco Exploration Canada Ltd.
Gold Creek	NW26-67-5W6	Atlantic Richfield Canada Ltd.
Harmattan	NE27-31-4W5	Canadian Superior Oil Ltd.*
Homeglen-Rimbey	S5-44-1SW5	Gulf Oil Canada Ltd.
Judy Creek	15-25-64-11W5	Imperial Oil Ltd.*
Jumping Pound	13-13-25-5W5	Shell Canada Ltd.
Kaybob South	15-59-18W5	Chevron Standard Ltd.
Kaybob South	1&12-62-20W5	Hudson's Bay Oil and Gas Co. Ltd.*
Leduc-Woodbend	2-34-50-26W4	Imperial Oil Ltd.
Lone Pine Creek	23-30-28W4	Hudson's Bay Oil and Gas Co. Ltd.
Minnehik-Buck Lake	10-5-46-6W5	Can Del Oil Ltd.
Mitsue	30-72-4W5	Amoco Canada Petroleum Co. Ltd.
Mitsue	30-72-4W5	Chevron Standard Ltd.
Nevis	NE33-38-22W4	Gulf Oil Canada Ltd.
Nevis	SE22-39-22W4	Chevron Standard Ltd.
Pembina	13-24-48-7W5	Goliad Oil and Gas Company
Pincher Creek	23-4-29W4	Gulf Oil Canada Ltd.
Quirk Creek	4-21-4-W5	Imperial Oil Ltd.
Rainbow	10-10-109-8W6	Aquitaine Company of Canada Ltd.
Rainbow	10-110-6W6	Mobil Oil Canada Ltd.
Ricinus	11-30-35-8W5	Amoco Canada Petroleum Company Ltd.
Simonette	6-63-25W5	Shell Canada Limited
Strachan	35-37-9W5	Gulf Oil Canada Ltd.
Strachan	2-37-10W5	Aquitaine Company of Canada Ltd.
Sylvan Lake	14-32-37-3W5	Hudson's Bay Oil and Gas Co. Ltd.
Waterton	2-20-4-30W4	Shell Canada Ltd.
Wildcat Hills	6-16-26-5W5	Petrofina Canada Ltd.
Wimborne	12-34-26W4	Mobil Oil Canada, Ltd.
Windfall	8-17-60-15W5	Amoco Canada Petroleum Co. Ltd.
Steelman	21-4-5W2	Steelman Gas Ltd. (Dome Petroleum)
Taylor		Westcoast Petroleum Ltd.

*More than one plant

NATIONAL ENERGY BOARD
PENTANES PLUS PRODUCTION FORECAST

PLANT . . . .

SUBMITTOR . . . .

DATE . . . .

PRODUCTION FORECAST
FROM ESTABLISHED RESERVES
AT 1-1-76

YEAR	BARRELS PER DAY
1976	. . . .
1977	. . . .
1978	. . . .
1979	. . . .
1980	. . . .
1981	. . . .
1982	. . . .
1983	. . . .
1984	. . . .
1985	. . . .
1986	. . . .
1987	. . . .
1988	. . . .
1989	. . . .
1990	. . . .
1991	. . . .
1992	. . . .
1993	. . . .
1994	. . . .
1995	. . . .

1975
AVERAGE GAS COMPOSITION
(MOL PERCENT)

COMPONENT	PLANT INLET GAS	PLANT SALES GAS
Methane	. . . .	. . . .
Ethane	. . . .	. . . .
Propane	. . . .	. . . .
Butanes	. . . .	. . . .
Pentanes+	. . . .	. . . .
Nitrogen	. . . .	. . . .
Hydrogen Sulphide	. . . .	. . . .
Other	. . . .	. . . .

If liquids production is batch shipped to a reprocessing facility, name that facility.

. . . .

If liquids are produced into a pipeline system, identify the system.

. . . .

GAS RESERVES OF POOLS DEDICATED TO PLANT

POOL	GAS PURCHASER BY WHOM RESERVES CONTRACTED*	CURRENT PRODUCTION RATE (MMCFD)	INITIAL RESERVES	CUMULATIVE PRODUCTION AT 1-1-76
			(BCF @ 14.73 PSIA)	
. . . .	. . . .	. . . .	. . . .	. . . .
. . . .	. . . .	. . . .	. . . .	. . . .
. . . .	. . . .	. . . .	. . . .	. . . .
. . . .	. . . .	. . . .	. . . .	. . . .
. . . .	. . . .	. . . .	. . . .	. . . .
. . . .	. . . .	. . . .	. . . .	. . . .

*If there is more than one gas purchaser for any one pool, indicate all purchasers and percentage of pool total contracted by each.

RECONCILIATION OF TOTAL MARKET PRODUCT SALES & FEEDSTOCK REQUIREMENTS

Mb/d

	1974					
	East of the Ottawa Valley line		**West of the Ottawa Valley line**		**Canada**	
Total market product sales		749		850		1599
Deduct Product imports	(46)		(24)		(70)	
Add Product exports	110		29		139	
Net exports/(imports)		64		5		69
Net product transfers out/(in)		28		(28)		0
Industry use and loss & other adjustments		47		51		98
Total feedstock requirements		888		878		1766
Deduct gas plant butanes supplied to refineries		(0)		(13)		(13)
Deduct foreign feedstock refined		(811)		(2)		(813)
Canadian feedstock refined		77		863		940
Canadian feedstock by type:						
Lloydminster type		–		17		17
Other Heavy crude		–		51		51
Pentanes Plus -- segregated		–		28		28
Synthetic crude		–		23		23
Other Light & Medium		77		744		821

ESTABLISHED RESERVES OF CONVENTIONAL CRUDE OIL
NEB Estimates

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/76 MMstb	Remaining Reserves at 1/1/76 MMstb
NORTHWEST TERRITORIES			
1. Norman Wells			
Norman Wells	60.0	18.8	41.2
Total	**60.0**	**18.8**	**41.2**
BRITISH COLUMBIA			
1. Blueberry — Taylor Pipelines			
Aitken Creek — Gething	5.8	4.3	1.5
Blueberry — Debolt	13.5	10.3	3.2
Inga — Inga	32.6	21.8	10.8
Other	1.3	1.1	0.2
Total	**53.2**	**37.5**	**15.7**
2. Trans-Prairie Pipelines Ltd.: Beatton River — Taylor			
Beatton River — Halfway	8.9	6.1	2.8
Beatton River West — Bluesky Gething	4.4	2.4	2.0
Crush — Halfway	4.4	2.4	2.0
Currant — Halfway	2.7	1.9	0.8
Milligan Creek — Halfway	41.7	35.5	6.2
Peejay — Halfway	56.1	47.4	8.7
Weasel — Halfway	15.1	10.6	4.5
Wildmint — Halfway	7.4	6.8	0.6
Other	5.0	2.5	2.5
Total	**145.7**	**115.6**	**30.1**
3. Trans-Prairie Pipelines Ltd.: Boundary Lake — Taylor			
Boundary Lake Unit No. 1	106.6	52.2	54.4
Boundary Lake Unit No. 2	67.8	41.1	26.7
Other	20.9	14.1	6.8
Total	**195.3**	**107.4**	**87.9**
4. Trucked Oil (B.C. Total)			
Trucked Oil	6.4	2.0	4.4
Total	**6.4**	**2.0**	**4.4**
BRITISH COLUMBIA TOTAL	**400.6**	**262.5**	**138.1**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/76 MMstb	Remaining Reserves at 1/1/76 MMstb
ALBERTA			
1. Bow River Pipe Lines Ltd.: Light & Medium			
Provost — Viking CAK	90.0	20.8	69.2
Other	6.1	1.3	4.8
Total	**96.1**	**22.1**	**74.0**
2. Bow River Pipe Lines Ltd.: Heavy			
Bantry — Mannville A	40.6	21.1	19.5
Countess — Upper Mannville D	27.6	10.5	17.1
Countess — Upper Mannville H	14.8	4.6	10.2
Grand Forks — Lower Mannville D	34.2	3.8	30.4
Hays — Lower Mannville A	9.4	4.5	4.9
Lathom — Upper Mannville A	10.1	3.6	6.5
Taber — Mannville D	12.4	5.5	6.9
Taber South — Mannville B	11.1	8.3	2.8
Other	76.4	34.0	42.4
Total	**236.6**	**95.9**	**140.7**
3. BP Exploration Canada Limited			
Chauvin — Mannville A	7.7	4.8	2.9
Chauvin South — Sparky A & B	9.2	3.4	5.8
Chauvin South — Sparky E	2.0	0.9	1.1
Chauvin South — Sparky H	1.4	0.4	1.0
Chauvin South — Lloydminster D	1.7	0.8	0.9
Other	7.0	2.0	5.0
Total	**29.0**	**12.3**	**16.7**
4. Cremona Pipeline			
Crossfield — Cardium A	17.9	15.2	2.7
Harmattan East — Rundle	80.8	41.1	39.7
Harmattan Elkton — Rundle C	53.9	35.6	18.3
Other	30.9	20.9	10.0
Total	**183.5**	**112.8**	**70.7**
5. Federated Pipe Lines Ltd.			
Carson Creek North — BHL A	36.2	13.5	22.7
Carson Creek North — BHL B	124.1	47.9	76.2
Judy Creek — BHL A	390.0	171.9	218.1
Judy Creek — BHL B	125.0	56.2	68.8
Swan Hills — BHL A & B	778.0	317.4	460.6
Swan Hills — BHL C	190.0	69.2	120.8

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/76 MMstb	Remaining Reserves at 1/1/76 MMstb
ALBERTA (continued)			
Swan Hills South – BHL A & B	452.8	169.5	283.3
Virginia Hills – BHL	155.0	79.5	75.5
Other	40.5	11.2	29.3
Total	**2291.6**	**936.3**	**1355.3**
6. Gibson Petroleum Company Limited			
Bellshill Lake – Blairmore	49.9	24.2	25.7
Thompson Lake – Blairmore	4.1	2.4	1.7
Total	**54.0**	**26.6**	**27.4**
7. Gulf Alberta Pipe Line			
Clive – D-2A	21.6	5.9	15.7
Clive – D-3A	43.4	14.3	29.1
Drumheller – D-2B	10.3	3.5	6.8
Duhamel – D-2A	5.8	4.9	.9
Duhamel – D-3B	7.1	5.4	1.7
Erskine – D-3	24.2	18.4	5.8
Fenn Big Valley – D-2A	239.0	149.8	89.2
Hussar – Glauconitic A	20.6	11.0	9.6
Joffre – D-2 (33%)	23.3	10.4	12.9
Stettler – D-2A	24.0	20.9	3.1
Stettler – D-3A	23.2	13.3	9.9
West Drumheller – D-2A	27.5	20.9	6.6
Other	139.4	84.7	54.7
Total	**609.4**	**363.4**	**246.0**
8. Husky Pipeline Ltd & Manito Pipelines Ltd.			
Lloydminster – Sparky C and GP A	7.2	4.6	2.6
Lloydminster – Sparky and GP C	18.0	10.7	7.3
Viking Kinsella – Wainwright B	27.5	0.2	27.3
Wainwright – Wainwright & Sparky A	62.7	31.1	31.6
Wildmere – Lloydminster A & Sparky B	15.4	1.2	14.2
Other	14.8	6.9	7.9
Total	**145.6**	**54.7**	**90.9**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/76 MMstb	Remaining Reserves at 1/1/76 MMstb
ALBERTA (continued)			
9. The Imperial Pipe Line Company, Limited: Ellerslie			
Acheson — D-3A	107.9	64.4	43.5
Golden Spike — D-3A	210.0	139.1	70.9
Other	62.4	33.4	29.0
Total	**380.3**	**236.9**	**143.4**
10. The Imperial Pipe Line Company, Limited: Excelsior			
Excelsior — D-2	23.8	18.7	5.1
Fairydell Bon Accord — D-3A	11.5	7.7	3.8
Other	4.4	3.6	.8
Total	**39.7**	**30.0**	**9.7**
11. The Imperial Pipe Line Company, Limited: Leduc			
Leduc Woodbend — D-2A	86.5	85.1	1.4
Leduc Woodbend — D-3A	241.3	213.3	28.0
Other	41.8	36.9	4.9
Total	**369.6**	**335.3**	**34.3**
12. The Imperial Pipe Line Company, Limited: Redwater			
Redwater — D-3	797.0	571.0	226.0
Total	**797.0**	**571.0**	**226.0**
13. Murphy Milk River Pipe Line			
Coutts — Total	5.0	1.1	3.9
Manyberries — Total	4.7	1.3	3.4
Red Coulee — Total	3.8	2.7	1.1
Other	8.7	4.5	4.2
Total	**22.2**	**9.6**	**12.6**
14. Norcen Energy Resources Ltd.			
Joarcam — Viking	90.2	77.7	12.5
Total	**90.2**	**77.7**	**12.5**
15. Peace River Oil Pipe Line Co. Ltd.			
Goose River — BHL A	49.2	17.0	32.2
Kaybob — BHL A	114.0	58.8	55.2
Kaybob South — Triassic A	87.5	29.3	58.2
Nipisi — Gilwood A (33%)	99.0	35.4	63.6
Simonette — D-3	57.8	22.4	35.4

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/76 MMstb	Remaining Reserves at 1/1/76 MMstb
ALBERTA (continued)			
Snipe Lake – BHL	77.0	31.8	45.2
Sturgeon Lake – D-3	22.8	14.2	8.6
Sturgeon Lake South – D-3	157.0	71.7	85.3
Utikuma – KR Sand A	28.0	9.0	19.0
Other	128.6	46.5	82.1
Total	**820.9**	**336.1**	**484.8**
16. Pembina Pipe Line Ltd.			
Pembina – Cardium	1367.3	799.2	568.1
Pembina – Keystone Belly River B	60.1	17.9	42.2
Willesden Green – Cardium A (70%)	104.3	41.2	63.1
Other	111.5	36.5	75.0
Total	**1643.2**	**894.8**	**748.4**
17. Rainbow Pipe Line Company, Ltd.			
Mitsue – Gilwood A	341.0	120.8	220.2
Nipisi – Gilwood A (67%)	201.0	71.9	129.1
Rainbow – KR A	63.0	27.0	36.0
Rainbow – KR B	171.6	61.9	109.7
I.S. No. 1 Other	89.5	26.1	63.4
Rainbow – KR F	120.0	39.6	80.4
Rainbow – KR AA	78.3	19.8	58.5
I.S. No. 11 Other	25.7	10.5	15.2
I.S. No. 2 Total	28.8	8.1	20.7
Rainbow Other	89.9	25.8	64.1
Rainbow South – KR A	19.4	6.6	12.8
Rainbow South – KR B	32.8	8.4	24.4
Rainbow South – KR E	25.2	7.2	18.0
Virgo – Total	55.0	24.3	30.7
Zama – Total	91.0	43.8	47.2
Other	79.7	18.9	60.8
Total	**1511.9**	**520.7**	**991.2**
18. Rangeland Pipeline Company Limited			
Ferrier – Cardium D	12.1	3.9	8.2
Ferrier – Cardium E	23.3	5.2	18.1
Gilby – Jurassic B	20.5	8.3	12.2
Gilby – Mannville B	15.1	3.5	11.6
Gilby – Viking A	16.2	13.8	2.4
Innisfail – D-3	74.4	43.6	30.8

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/76 MMstb	Remaining Reserves at 1/1/76 MMstb
ALBERTA (continued)			
Joffre — D-2 (67%)	47.3	21.2	26.1
Medicine River — Glauconitic A	11.2	3.9	7.3
Medicine River — Jurassic A	11.3	6.1	5.2
Medicine River — Jurassic D	18.8	4.8	14.0
Sundre — Rundle A	32.0	20.4	11.6
Willesden Green — Cardium A (30%)	44.7	17.6	27.1
Other	182.9	80.9	102.0
Total	**509.8**	**233.2**	**276.6**
19. Texaco Exploration Canada Ltd.			
Bonnie Glen — D-3A	460.3	249.9	210.4
Glen Park — D-3A	21.1	11.5	9.6
Westerose — D-3	133.4	59.5	73.9
Wizard Lake — D-3A	323.0	161.9	161.1
Other	10.0	9.2	0.8
Total	**947.8**	**492.0**	**455.8**
20. Trans-Prairie Pipelines Ltd.: Boundary Lake South			
Boundary Lake South — Triassic E	22.5	5.0	17.5
Other	4.1	0.8	3.3
Total	**26.6**	**5.8**	**20.8**
21. Twining Pipeline Division			
Twining — Rundle A and LM A	22.4	4.9	17.5
Twining North — Rundle	4.4	1.6	2.8
Total	**26.8**	**6.5**	**20.3**
22. Valley Pipe Line			
Turner Valley — Rundle & Shallow	141.5	125.7	15.8
Total	**141.5**	**125.7**	**15.8**
23. Truck and Tank Car			
Cessford — Total	25.3	14.6	10.7
Other	27.7	14.6	13.1
Total	**53.0**	**29.2**	**23.8**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/76 MMstb	Remaining Reserves at 1/1/76 MMstb
24. Undefined and Confidential			
Light	31.2	8.1	23.1
Heavy	16.1	2.2	13.9
Total	**47.3**	**10.3**	**37.0**
ALBERTA TOTAL	**11073.6**	**5539.0**	**5534.6**
SASKATCHEWAN			
1. Husky Pipeline Ltd. & Manito Pipelines Ltd.			
Aberfeldy – Sparky, Aberfeldy Unit	31.0	20.3	10.7
South Aberfeldy – Sparky, Voluntary Unit	10.9	5.8	5.1
Dulwich – Sparky	11.1	8.5	2.6
Epping – Sparky & G.P., Non Unit	12.1	8.2	3.9
South Epping – Sparky & G.P., Unit No. 1	17.3	10.4	6.9
S.W. Epping – Sparky, Vol. Unit No. 1	5.4	2.6	2.8
Furness – Sparky	2.3	1.3	1.0
Golden Lake North – Waseca & Sparky, Vol. Unit	9.7	5.0	4.7
Golden Lake North – Waseca & Sparky, Non-Unit	2.5	0.8	1.7
Golden Lake South – Sparky	2.8	1.0	1.8
Golden Lake South – Waseca	6.5	2.7	3.8
Gully Lake – Waseca, Vol. Unit No. 1	4.6	1.9	2.7
Gully Lake – Waseca, Non-Unit	2.5	0.9	1.6
Lashburn – Waseca, Vol. Unit	5.3	3.9	1.4
Lone Rock – Sparky	7.1	6.7	0.4
Tangleflags (Total)	8.2	1.9	6.3
Other	34.3	20.9	13.4
Total	**173.6**	**102.8**	**70.8**
2. Bow River Pipe Lines Ltd. (Heavy Blend)			
Coleville – Bakken	46.3	28.2	18.1
North Hoosier – Bakken, Vol. Unit	6.5	2.7	3.8
North Hoosier – Basal Blairmore, Vol. Unit	3.6	2.1	1.5
Other – Heavy	5.2	2.0	3.2
Smiley Dewar – Viking (100%)	32.7	20.5	12.2
Plato – Viking (100%)	2.9	1.4	1.5
Dodsland – Viking, Eagle Lake Vol. Unit (27%)	4.3	2.1	2.2
Dodsland – Viking, Gleneath Unit (27%)	3.7	1.9	1.8

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/76 MMstb	Remaining Reserves at 1/1/76 MMstb
SASKATCHEWAN (continued)			
Eureka – Viking, South Unit (27%)	2.0	1.3	0.7
Other – Light (27%)	5.1	3.5	1.6
Total	**112.3**	**65.7**	**46.6**
3. Bow River Pipe Lines Ltd. (Light)			
Dodsland – Viking, Eagle Lake Vol. Unit (73%)	11.5	5.6	5.9
Dodsland – Viking, Gleneath Unit (73%)	9.9	5.2	4.7
Eureka – Viking, South Unit (73%)	5.5	3.4	2.1
Other – Light (73%)	13.7	9.3	4.4
Total	**40.6**	**23.5**	**17.1**
4. South Saskatchewan Pipe Line Company			
Battrum – Roseray, Unit No. 1	36.1	21.8	14.3
Cantuar Main – Cantuar, Unit	23.7	17.1	6.6
Dollard – Upper Shaunavon, Unit	83.6	67.3	16.3
Fosterton – Roseray, Main Unit	64.2	47.5	16.7
Gull Lake North – Upper Shaunavon, Unit	19.6	15.9	3.7
Instow – Upper Shaunavon, Unit	51.0	36.9	14.1
Main Success – Roseray, Unit	16.1	14.8	1.3
North Premier – Roseray, Unit No. 3	13.2	10.8	2.4
Rapdan – Upper Shaunavon, Unit	17.5	10.5	7.0
South Success – Roseray, Unit	23.3	17.9	5.4
Suffield – Upper Shaunavon, Unit No. 2	6.2	2.4	3.8
Verlo – Roseray, Unit	9.0	3.6	5.4
Other	177.5	107.7	69.8
Total	**541.0**	**374.2**	**166.8**
5. Westspur Pipe Line Company – S.E. Sask. Medium			
Benson – Midale, Unit	10.5	6.3	4.2
Innes – Frobisher	13.3	7.8	5.5
Lost Horse Hill – Frobisher Alida, Vol. Unit No. 1	12.5	8.8	3.7
Midale – Central Midale, Unit	109.4	74.1	35.3
Midale – Central Midale, Non-Unit	5.5	3.8	1.7
Viewfield – Frobisher	7.0	2.5	4.5
Weyburn – Midale, Unit	332.1	209.0	123.1
Weyburn – Midale, Non-Unit	5.9	3.6	2.3
Other	90.0	54.8	35.2
Total	**586.2**	**370.7**	**215.5**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/76 MMstb	Remaining Reserves at 1/1/76 MMstb
SASKATCHEWAN (continued)			
6. Westspur – Medium Pipe Line – Batched Light			
Flat Lake – Ratcliffe, Vol. Unit No. 1	11.8	5.3	6.5
Freda Lake – Ratcliffe	2.4	1.4	1.0
Sherwood – Frobisher	11.4	7.9	3.5
Total	**25.6**	**14.6**	**11.0**
7. Westspur Pipe Line Company – S.E. Sask. Light			
Alida East – Alida, Unit	11.7	9.7	2.0
Carnduff – Midale, East Unit	16.3	14.4	1.9
Elmore – Frobisher Vol. Unit	11.8	7.4	4.4
Ingoldsby – Frobisher Alida, Vol. Unit	16.0	11.1	4.9
Kenosee – Tilston, Vol. Unit	10.8	6.6	4.2
Parkman – Tilston Souris Valley	17.2	14.1	3.1
Queensdale East-Frobisher Alida, Non-Unit	28.4	18.0	10.4
Rosebank – Frobisher Alida, Vol. Unit No. 1	22.5	18.9	3.6
Steelman – Midale, Unit IA	60.5	42.2	18.3
Steelman – Midale, Unit II	52.9	41.0	11.9
Steelman – Midale, Unit III	25.6	20.2	5.4
Steelman – Midale, Unit IV	32.5	21.8	10.7
Steelman – Midale, Unit VI	58.2	47.8	10.4
Willmar – Frobisher Alida, Non-Unit	19.0	13.3	5.7
Workman – Frobisher, Vol. Unit No. 1	10.9	8.0	2.9
Other	268.9	190.8	78.1
Total	**663.2**	**485.3**	**177.9**
SASKATCHEWAN TOTAL	**2142.5**	**1436.8**	**705.7**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/76 MMstb	Remaining Reserves at 1/1/76 MMstb
MANITOBA			
1. Trans-Prairie Pipelines Ltd.			
Daly — Mississippian	21.2	17.2	4.0
Routledge — Mississippian	14.2	11.9	2.3
North Virden Scallion — Mississippian	70.4	45.5	24.9
Virden Roselea — Mississippian	43.2	29.1	14.1
Other	8.6	6.7	1.9
Total	**157.6**	**110.4**	**47.2**
MANITOBA TOTAL	**157.6**	**110.4**	**47.2**
ONTARIO			
1. Ontario			
ONTARIO TOTAL	**60.9**	**53.4**	**7.5**
CANADA – TOTAL*	**13895.2**	**7420.9**	**6474.3**

*Frontier reserves not included.

POTENTIAL PRODUCIBILITY FROM ESTABLISHED CRUDE OIL RESERVES
NEB Forecast
b/d

LIGHT CRUDE OIL

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
NORTHWEST TERRITORIES																				
Norman Wells																				
Norman Wells	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000
Pipeline Total	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**
BRITISH COLUMBIA																				
Blueberry — Taylor Pipelines																				
Aitken Creek - Gething	1000	778	606	472	367	286	223	173	135	105	23	0	0	0	0	0	0	0	0	0
Blueberry - Debolt	990	888	797	716	642	576	517	464	417	374	336	301	270	243	218	195	175	157	141	127
Inga - Inga	4350	3744	3222	2773	2387	2054	1768	1522	1310	1127	970	835	719	618	532	458	394	339	292	251
Other	75	67	60	53	48	43	38	34	31	27	24	22	20	0	0	0	0	0	0	0
Pipeline Total	**6415**	**5478**	**4686**	**4015**	**3446**	**2961**	**2548**	**2195**	**1893**	**1635**	**1355**	**1159**	**1009**	**862**	**750**	**654**	**570**	**497**	**434**	**378**
Trans-Prairie Pipelines Ltd.: Beatton River Taylor																				
Beatton River - Halfway	950	842	747	662	587	521	462	410	363	322	286	253	225	199	177	157	139	123	109	90
Beatton River West Bluesky Gething	730	639	559	489	428	375	328	287	251	220	193	169	147	129	113	99	86	76	66	58
Crush - Halfway	750	653	570	497	433	378	329	287	250	218	190	166	144	126	110	96	83	73	63	55
Currant - Halfway	490	390	310	247	196	156	124	99	79	62	50	0	0	0	0	0	0	0	0	0
Milligan Creek - Halfway	2920	2431	2025	1686	1404	1169	973	811	675	562	468	390	324	270	225	187	156	130	108	47
Peejay - Halfway	4600	3743	3046	2479	2017	1642	1336	1087	885	720	586	477	388	316	257	209	48	0	0	0
Weasel - Halfway	2580	2047	1625	1290	1024	812	645	512	406	322	256	203	161	128	101	80	64	50	4	0
Wildmint - Halfway	320	261	214	175	143	117	96	78	64	52	43	17	0	0	0	0	0	0	0	0
Other	845	746	659	582	514	454	401	354	313	276	244	216	190	168	148	131	116	102	90	85
Pipeline Total	**14185**	**11757**	**9758**	**8111**	**6751**	**5628**	**4699**	**3929**	**3290**	**2759**	**2318**	**1893**	**1583**	**1338**	**1133**	**961**	**695**	**556**	**442**	**322**

LIGHT CRUDE OIL

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Trans-Prairie Pipelines Ltd.: Boundary Lake – Taylor																				
Boundary Lake Unit No. 1	9790	9192	8631	8104	7609	7144	6708	6298	5914	5553	5214	4895	4596	4316	4052	3805	3572	3354	3149	2957
Boundary Lake Unit No. 2	7600	6856	6185	5579	5033	4541	4096	3695	3333	3007	2713	2447	2208	1992	1797	1621	1462	1319	1190	1073
Other	1810	1639	1484	1344	1218	1103	999	905	819	742	672	609	551	499	452	409	371	336	304	275
Pipeline Total	**19200**	**17687**	**16301**	**15028**	**13861**	**12788**	**11804**	**10899**	**10067**	**9303**	**8599**	**7952**	**7356**	**6807**	**6302**	**5836**	**5406**	**5010**	**4644**	**4307**
Trucked Oil (B.C. Total)																				
Trucked Oil	775	728	684	643	604	568	534	502	471	443	416	391	368	346	325	305	287	270	253	238
British Columbia Total	**40575**	**35652**	**31431**	**27799**	**24663**	**21947**	**19585**	**17526**	**15724**	**14142**	**12690**	**11397**	**10318**	**9355**	**8512**	**7758**	**6959**	**6334**	**5775**	**5247**
ALBERTA																				
Bow River Pipe Lines Ltd.: Light & Medium																				
Provost – Viking CAK	10500	10500	10500	10500	10390	9758	9098	8483	7909	7375	6876	6411	5978	5574	5197	4845	4518	4212	3927	3662
Other	450	500	550	550	550	539	513	488	464	442	420	400	380	362	344	327	311	296	282	268
Pipeline Total	**10950**	**11000**	**11050**	**11050**	**10940**	**10298**	**9612**	**8972**	**8374**	**7817**	**7297**	**6811**	**6358**	**5936**	**5541**	**5173**	**4829**	**4509**	**4210**	**3930**

LIGHT CRUDE OIL

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Cremona Pipeline																				
Crossfield Cardium A	1150	1019	904	802	711	631	559	496	440	390	339	0	0	0	0	0	0	0	0	0
Harmattan East – Rundle	12000	9671	7987	6726	5754	4988	4372	3869	3452	3102	2805	2551	2332	2141	1974	1827	1696	1580	1476	1382
Harmattan Elkton – Rundle C	7000	6283	5087	4187	3495	2954	2522	2174	1890	1655	1459	1294	1154	1035	932	842	765	697	637	584
Other	4080	3437	2830	2372	2017	1736	1509	1324	1171	1042	932	778	706	643	588	540	498	461	427	398
Pipeline Total	**24230**	**20413**	**16811**	**14089**	**11979**	**10309**	**8964**	**7865**	**6954**	**6191**	**5537**	**4625**	**4193**	**3820**	**3495**	**3210**	**2960**	**2738**	**2541**	**2365**
Federated Pipe Lines Ltd.																				
Carson Creek North – BHL A	5100	5300	5300	5221	4719	4206	3749	3342	2979	2655	2367	2110	1880	1676	1494	1332	1187	1058	943	840
Carson Creek North – BHL B	19000	20250	21500	20060	17404	15100	13101	11367	9862	8557	7424	6441	5588	4848	4207	3650	3166	2747	2383	2068
Judy Creek – BHL A	84500	72729	62599	53879	46374	39914	34355	29569	25450	21905	18854	16228	13967	12022	10347	8906	7665	6597	5678	4887
Judy Creek – BHL B	25150	21864	19007	16524	14365	12489	10857	9439	8205	7133	6201	5391	4687	4074	3542	3079	2677	2327	2023	1759
Swan Hills – BHL A & B	98000	98000	97771	91480	83106	75499	68588	62310	56606	51425	46717	42441	38556	35027	31821	28908	26262	23858	21674	19690
Swan Hills – BHL C	18950	17917	16942	16019	15147	14322	13542	12804	12107	11447	10824	10234	9677	9150	8652	8180	7735	7314	6915	6539
Swan Hills South – BHL A & B	70000	70000	70000	69985	64998	56789	49618	43352	37877	33094	28914	25263	22073	19285	16850	14722	12863	11238	9819	8579
Virginia Hills – BHL	23100	20569	18317	16310	14524	12933	11517	10255	9132	8132	7241	6448	5742	5113	4553	4054	3610	3215	2862	2549
Other	6185	5876	5603	5208	4689	4160	3694	3282	2918	2597	2312	2061	1838	1640	1465	1310	1172	1049	940	844
Pipeline Total	**349985**	**332508**	**317041**	**294690**	**265330**	**235417**	**209024**	**185723**	**165141**	**146948**	**130859**	**116620**	**104012**	**92839**	**82933**	**74144**	**66340**	**59407**	**53243**	**47758**
Gibson Petroleum Company Limited																				
Bellshill Lake – Blairmore	6910	6277	5702	5180	4706	4275	3884	3528	3205	2912	2645	2403	2183	1983	1802	1637	1487	1351	1227	1115
Thompson Lake – Blairmore	500	452	409	370	335	303	274	248	224	203	183	166	150	136	123	111	100	91	82	74
Pipeline Total	**7410**	**6729**	**6112**	**5551**	**5041**	**4579**	**4158**	**3777**	**3430**	**3115**	**2829**	**2570**	**2334**	**2119**	**1925**	**1748**	**1588**	**1442**	**1310**	**1189**

LIGHT CRUDE OIL

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Gulf Alberta Pipe Line																				
Clive – D-2A	2900	2900	2900	2900	2900	2900	1923	1720	1547	1400	1274	1165	1071	988	915	850	792	741	694	652
Clive – D-3A	5900	5900	5900	5900	5900	5799	5212	4622	4100	3636	3225	2860	2537	2250	1995	1770	1569	1392	1234	1095
Drumheller – D-2B	1900	1900	1900	1863	1634	1406	1210	1042	896	771	664	571	492	423	364	313	270	232	200	172
Duhamel – D-2A	550	441	354	284	228	183	146	117	94	75	4	0	0	0	0	0	0	0	0	0
Duhamel – D-3B	905	748	612	501	410	336	275	225	184	151	123	101	82	0	0	0	0	0	0	0
Erskine – D-3	1500	1338	1205	1095	1002	923	855	795	743	697	655	618	585	555	528	503	480	459	440	422
Fenn Big Valley – D-2A	38000	34911	29161	24357	20345	16993	14194	11856	9903	8271	6909	5771	4820	4026	3363	2809	2346	1959	1636	1367
Hussar – Glauconitic A	2900	2597	2327	2084	1867	1673	1498	1342	1202	1077	965	864	774	693	621	556	498	446	400	358
Joffre – D-2 (33%)	1500	1700	1900	2100	2100	2100	2100	2100	2043	1855	1678	1519	1374	1243	1125	1018	921	833	754	682
Stettler – D-2A	1220	1065	931	813	710	621	542	474	414	361	316	276	241	210	184	161	8	0	0	0
Stettler – D-3A	2900	2900	2900	2714	2336	2011	1731	1489	1282	1103	950	817	703	605	521	448	386	332	286	246
West Drumheller – D-2A	2734	2378	2067	1797	1562	1358	1181	1026	892	775	674	586	509	443	92	0	0	0	0	0
Other	10900	10845	10183	9400	8677	8010	7394	6825	6301	5816	5369	4956	4575	4223	3899	3599	3322	3067	2831	2613
Pipeline Total	**73809**	**69627**	**62343**	**55813**	**49677**	**44317**	**38266**	**33640**	**29607**	**25996**	**22812**	**20110**	**17769**	**15665**	**13611**	**12031**	**10596**	**9465**	**8478**	**7610**
The Imperial Pipe Line Company, Limited: Ellerslie																				
Acheson – D-3A	16000	16000	16000	15607	12646	9848	7670	5973	4652	3623	2821	2197	1711	1332	1038	808	629	490	126	0
Golden Spike – D-3A	43310	33740	26277	20464	15938	12412	9666	7528	5863	4566	3556	2769	2156	1679	1308	1018	793	617	481	94
Other	8800	8447	7505	6656	5903	5236	4644	4118	3653	3240	2873	2548	2260	2004	1778	1577	1398	1240	1100	975
Pipeline Total	**68110**	**58187**	**49782**	**42728**	**34487**	**27497**	**21981**	**17621**	**14168**	**11429**	**9251**	**7515**	**6128**	**5017**	**4124**	**3404**	**2821**	**2348**	**1708**	**1070**
The Imperial Pipe Line Company, Limited: Excelsior																				
Excelsior – D2	2500	2067	1709	1413	1169	966	799	661	546	452	373	309	255	211	174	144	119	103	0	0
Fairydell Bon Accord – D-3A	1640	1397	1190	1014	864	736	627	535	455	388	331	282	240	204	174	148	126	108	52	0
Other	516	431	361	302	253	212	177	149	124	104	87	73	61	51	43	36	30	26	6	0
Pipeline Total	**4656**	**3896**	**3262**	**2731**	**2287**	**1916**	**1605**	**1345**	**1127**	**945**	**792**	**665**	**557**	**468**	**393**	**329**	**277**	**238**	**58**	**0**

LIGHT CRUDE OIL

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
The Imperial Pipe Line Company, Limited: Leduc																				
Leduc Woodbend – D-2A	850	680	566	485	425	377	340	161	0	0	0	0	0	0	0	0	0	0	0	0
Leduc Woodbend – D-3A	14750	11992	9749	7926	6444	5239	4259	3463	2815	2289	1861	1513	1230	1000	813	661	537	193	0	0
Other	1200	1147	1049	958	876	800	731	668	611	558	510	466	426	389	356	325	297	271	248	227
Pipeline Total	**16800**	**13819**	**11365**	**9371**	**7745**	**6418**	**5331**	**4293**	**3427**	**2847**	**2371**	**1979**	**1656**	**1390**	**1169**	**986**	**835**	**465**	**248**	**227**
The Imperial Pipe Line Company, Limited: Redwater																				
Redwater – D-3	128990	112906	87056	67125	51757	39907	30770	23725	18293	14105	10876	8385	6466	4985	3844	2964	2285	1762	1358	1047
Pipeline Total	**128990**	**112906**	**87056**	**67125**	**51757**	**39907**	**30770**	**23725**	**18293**	**14105**	**10876**	**8385**	**6466**	**4985**	**3844**	**2964**	**2285**	**1762**	**1358**	**1047**
Murphy Milk River Pipe Line																				
Coutts – Total	1050	1050	1050	1031	907	783	676	583	504	435	375	324	280	241	208	180	155	134	115	100
Manyberries – Total	470	447	426	406	387	369	352	335	320	305	290	277	264	251	240	228	218	207	198	188
Red Coulee – Total	190	180	170	162	153	145	138	131	124	117	111	106	100	95	90	85	81	77	73	69
Other	1130	1022	925	837	757	685	620	561	507	459	415	376	340	307	278	252	228	206	186	169
Pipeline Total	**2840**	**2700**	**2573**	**2437**	**2206**	**1984**	**1787**	**1612**	**1456**	**1317**	**1194**	**1083**	**985**	**896**	**817**	**746**	**683**	**625**	**573**	**527**
Norcen Energy Resources Ltd.																				
Joarcam – Viking	7010	5676	4596	3722	3014	2440	1976	1600	1296	1049	849	688	340	0	0	0	0	0	0	0
Pipeline Total	**7010**	**5676**	**4596**	**3722**	**3014**	**2440**	**1976**	**1600**	**1296**	**1049**	**849**	**688**	**340**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

LIGHT CRUDE OIL

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Peace River Oil Pipe Line Co. Ltd.																				
Goose River – BHL A	5569	5227	4836	4481	4159	3866	3599	3354	3130	2925	2737	2564	2404	2257	2121	1996	1879	1771	1671	1578
Kaybob – BHL A	13500	17000	16493	14457	12569	10927	9499	8258	7179	6241	5426	4717	4101	3565	3099	2694	2342	2036	1770	1539
Kaybob South – Triassic A	16000	16000	15334	13620	12080	10714	9502	8428	7475	6629	5880	5215	4625	4102	3638	3227	2862	2538	2251	1996
Nipisi – Gilwood A (33%)	17160	17160	17160	16323	14213	12356	10742	9339	8119	7058	6136	5334	4637	4031	3505	3047	2649	2303	2002	1740
Simonette – D-3	11380	11440	11500	10596	8852	7393	6175	5158	4308	3598	3006	2510	2097	1751	1463	1222	1020	852	712	594
Snipe Lake – BHL	8370	8306	7824	7295	6801	6342	5913	5513	5140	4793	4469	4167	3885	3622	3377	3149	2936	2737	2552	2380
Sturgeon Lake – D-3	3930	3388	2841	2382	1998	1675	1405	1178	988	828	695	582	488	409	343	288	134	0	0	0
Sturgeon Lake South – D-3	22000	22000	22000	22000	21055	18197	15662	13481	11603	9987	8595	7398	6368	5481	4717	4060	3494	3008	2589	2228
Utikuma – KR Sand A	6000	5848	5182	4550	3996	3508	3081	2705	2375	2086	1831	1608	1412	1240	1089	956	839	737	647	568
Other	10500	10500	10398	9926	9442	8981	8543	8127	7730	7353	6996	6653	6329	6020	5727	5447	5182	4929	4688	4460
Pipeline Total	**114409**	**116870**	**113570**	**105634**	**95169**	**83964**	**74126**	**65544**	**58052**	**51503**	**45773**	**40753**	**36350**	**32483**	**29083**	**26089**	**23342**	**20915**	**18886**	**17087**
Pembina Pipe Line Ltd.																				
Pembina – Cardium	74000	65405	58477	52783	48028	44002	40553	37569	34963	32670	30638	28826	27201	25736	24410	23203	22101	21091	20163	19307
Pembina – Keystone Belly River B	10200	9981	9099	8250	7479	6781	6148	5574	5054	4582	4154	3766	3415	3096	2807	2545	2307	2092	1896	1719
Willesden Green – Cardium A (70%)	9450	8652	7951	7331	6779	6287	5846	5449	5091	4767	4472	4203	3958	3733	3527	3337	3162	3000	2850	2711
Other	8650	8302	7969	7648	7341	7046	6763	6491	6231	5980	5740	5509	5288	5076	4872	4676	4488	4308	4135	3969
Pipeline Total	**102300**	**92342**	**83497**	**76013**	**69629**	**64118**	**59312**	**55085**	**51340**	**48001**	**45006**	**42307**	**39864**	**37643**	**35617**	**33762**	**32060**	**30493**	**29046**	**27707**
Rainbow Pipe Line Company, Ltd.																				
Mitsue – Gilwood A	50000	50000	50000	47938	42981	38503	34493	30900	27681	24797	22214	19900	17827	15970	14307	12816	11481	10285	9214	8254
Nipisi – Gilwood A (67%)	34840	34840	34840	33124	28841	25073	21798	18950	16474	14322	12451	10824	9410	8181	7112	6183	5375	4673	4062	3531
Rainbow – KR A	6000	6000	6000	6000	6000	5945	5509	5035	4602	4206	3844	3513	3210	2934	2681	2451	2240	2047	1871	1710
Rainbow – KR B	28000	28000	28000	28000	26358	22703	19540	16818	14476	12459	10724	9230	7944	6838	5885	5065	4360	3752	3230	2780
I.S. No. 1 Other	14000	14000	13860	12736	11524	10427	9435	8537	7725	6989	6324	5722	5178	4685	4239	3836	3471	3140	2841	2571
Rainbow – KR F	17000	17000	17000	17000	17000	17000	16439	14268	12280	10570	9097	7830	6739	5801	4993	4297	3698	3183	2740	2358
Rainbow – KR AA	13000	13000	13000	13000	13000	12918	11555	9945	8560	7367	6341	5458	4697	4043	3480	2995	2578	2219	1910	1643
I.S. No. 11 Other	4300	4079	3654	3273	2932	2627	2353	2108	1888	1692	1515	1357	1216	1089	976	874	783	701	628	563
I.S. No. 2 Total	5200	5199	4918	4406	3947	3536	3167	2837	2542	2277	2040	1827	1637	1466	1314	1177	1054	944	846	758
Rainbow Other	11200	11152	10554	9841	9175	8555	7977	7437	6934	6466	6028	5621	5241	4886	4556	4248	3961	3693	3443	3210
Rainbow South – KR A	2500	3146	2847	2576	2331	2109	1908	1727	1562	1413	1279	1157	1047	947	857	776	702	635	574	520
Rainbow South – KR B	5500	5500	5500	5500	5500	5417	4772	4108	3535	3043	2619	2254	1940	1670	1437	1237	1064	916	788	679
Rainbow South – KR E	3000	4000	4000	4000	4000	3999	3711	3194	2749	2366	2037	1753	1509	1298	1118	962	828	712	613	528
Virgo – Total	6400	6316	5873	5421	5004	4620	4264	3937	3634	3354	3097	2858	2639	2436	2248	2075	1916	1769	1633	1507
Zama – Total	10500	10466	9803	8959	8188	7483	6839	6251	5713	5221	4771	4361	3985	3642	3329	3042	2780	2541	2322	2122
Other	8600	8600	8595	8280	7798	7344	6916	6513	6134	5777	5440	5124	4825	4544	4279	4030	3795	3574	3366	3170
Pipeline Total	**220040**	**221301**	**218448**	**210060**	**194584**	**178267**	**160685**	**142572**	**126496**	**112327**	**99829**	**88797**	**79052**	**70438**	**62817**	**56071**	**50093**	**44792**	**40088**	**35911**

LIGHT CRUDE OIL

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Rangeland Pipeline Company Limited																				
Ferrier – Cardium D	1800	1800	1725	1537	1373	1232	1108	1001	906	823	749	684	626	574	528	486	449	415	384	357
Ferrier – Cardium E	1775	1770	1646	1494	1367	1260	1169	1090	1021	960	906	858	815	775	740	707	678	650	625	602
Gilby – Jurassic B	1800	1900	2000	1999	1892	1720	1571	1440	1326	1224	1133	1053	980	915	856	803	754	710	669	632
Gilby – Mannville B	1700	1700	1700	1629	1493	1373	1266	1170	1084	1006	937	873	816	763	716	672	632	595	561	530
Gilby – Viking A	630	565	509	461	418	380	347	318	292	269	248	229	212	197	183	171	159	149	139	131
Innisfail – D-3	12000	12000	11161	9158	7497	6138	5026	4114	3369	2758	2258	1848	1513	1239	1014	830	680	556	455	373
Joffre – D-2 (67%)	3050	3453	3856	4260	4260	4260	4260	4260	4150	3770	3411	3086	2793	2527	2286	2069	1872	1694	1532	1387
Medicine River – Glauconitic A	1395	1276	1172	1079	996	922	855	795	740	691	646	605	568	534	502	473	447	422	400	379
Medicine River – Jurassic A	1500	1567	1405	1246	1105	980	869	771	684	606	538	477	423	375	332	295	261	232	206	182
Medicine River – Jurassic D	1450	1450	1450	1430	1323	1220	1130	1052	983	922	867	818	774	733	697	663	633	605	579	554
Sundre – Rundle A	3700	3334	3005	2708	2440	2199	1982	1786	1610	1451	1307	1178	1062	957	862	777	700	631	569	512
Willesden Green – Cardium A (30%)	4050	3708	3407	3141	2905	2694	2505	2335	2182	2043	1916	1801	1696	1600	1511	1430	1355	1285	1221	1162
Other	19432	19252	18423	16809	15097	13596	12319	11228	10232	9216	8320	7537	6848	6242	5706	5231	4809	4433	4096	3795
Pipeline Total	**54282**	**53779**	**51464**	**46956**	**42172**	**37981**	**34413**	**31366**	**28584**	**25744**	**23243**	**21054**	**19132**	**17438**	**15941**	**14614**	**13434**	**12383**	**11443**	**10601**
Texaco Exploration Canada Ltd.																				
Bonnie Glen – D-3A	100000	100000	89649	68517	52304	39928	30480	23268	17762	13559	10351	7901	6032	4604	3515	2683	2048	1563	1193	911
Glen Park – D-3A	3300	3211	2798	2408	2073	1784	1535	1321	1137	979	842	725	624	537	462	398	342	294	253	218
Westerose – D-3	26000	26000	25913	22713	18596	15225	12465	10205	8355	6841	5601	4585	3754	3073	2516	2060	1687	1381	1130	925
Wizard Lake – D-3A	67500	67500	67343	57084	43577	33265	25394	19385	14798	11296	8623	6583	5025	3836	2928	2235	1706	1302	994	759
Other	200	183	168	154	141	129	118	108	99	91	83	76	70	64	59	54	49	45	41	38
Pipeline Total	**197000**	**196895**	**185871**	**150878**	**116692**	**90333**	**69994**	**54290**	**42154**	**32768**	**25502**	**19873**	**15506**	**12117**	**9482**	**7431**	**5834**	**4588**	**3614**	**2853**
Trans-Prairie Pipelines Ltd.: Boundary Lake South																				
Boundary Lake South – Triassic E	3590	3222	2904	2627	2384	2170	1982	1815	1666	1534	1415	1308	1212	1126	1047	976	911	851	797	747
Other	654	587	529	478	434	395	361	330	303	279	257	238	221	205	190	177	166	155	145	136
Pipeline Total	**4244**	**3809**	**3433**	**3105**	**2818**	**2566**	**2343**	**2146**	**1970**	**1813**	**1673**	**1547**	**1433**	**1331**	**1238**	**1153**	**1077**	**1007**	**942**	**884**

LIGHT CRUDE OIL

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Twining Pipeline Division																				
Twining – Rundle A and LM A	4660	4216	3815	3452	3123	2826	2557	2314	2093	1894	1714	1551	1403	1269	1149	1039	940	851	770	696
Twining North – Rundle	570	610	650	630	571	517	468	423	383	346	313	284	257	232	210	190	172	155	141	127
Pipeline Total	**5230**	**4826**	**4465**	**4082**	**3695**	**3343**	**3025**	**2737**	**2477**	**2241**	**2028**	**1835**	**1660**	**1502**	**1359**	**1230**	**1113**	**1007**	**911**	**824**
Valley Pipe Line																				
Turner Valley – Rundle & Shallow	3100	3100	3100	3026	2804	2593	2399	2219	2052	1898	1756	1624	1502	1389	1285	1189	1099	1017	940	870
Pipeline Total	**3100**	**3100**	**3100**	**3026**	**2804**	**2593**	**2399**	**2219**	**2052**	**1898**	**1756**	**1624**	**1502**	**1389**	**1285**	**1189**	**1099**	**1017**	**940**	**870**
Alberta Total	**1395398**	**1330392**	**1235845**	**1109068**	**972035**	**848255**	**739781**	**646141**	**566407**	**498064**	**439486**	**388851**	**345306**	**307484**	**274682**	**246283**	**221274**	**199208**	**179606**	**162467**
SASKATCHEWAN																				
Bow River Pipe Lines Ltd. (Light)																				
Dodsland – Viking, Eagle Lake Vol. Unit (73%)	1060	999	942	888	837	789	743	701	661	623	587	553	522	492	464	437	412	388	366	345
Dodsland – Viking, Gleneath Unit (73%)	910	854	802	753	707	664	623	585	549	516	484	455	427	401	376	353	332	311	292	274
Eureka – Viking, South Unit (73%)	570	523	480	441	405	372	342	314	288	265	243	223	205	188	173	159	146	134	123	99
Other – Light (73%)	1505	1337	1188	1056	938	834	741	658	585	520	462	410	365	324	288	256	227	194	0	0
Pipeline Total	**4045**	**3714**	**3413**	**3139**	**2888**	**2660**	**2451**	**2260**	**2085**	**1925**	**1778**	**1643**	**1520**	**1406**	**1302**	**1206**	**1118**	**1029**	**782**	**720**

LIGHT CRUDE OIL

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Westspur – Medium Pipe Line – Batched Light																				
Flat Lake – Ratcliffe, Vol. Unit No. 1	1500	1384	1278	1179	1089	1005	928	856	790	730	673	622	574	530	489	451	417	384	355	328
Freda Lake – Ratcliffe	350	307	269	236	208	182	160	140	123	108	95	83	73	64	56	49	43	38	33	28
Sherwood – Frobisher	1025	920	825	741	665	597	536	481	432	387	348	312	280	251	225	202	182	163	146	131
Pipeline Total	**2875**	**2612**	**2373**	**2158**	**1962**	**1785**	**1624**	**1478**	**1346**	**1226**	**1117**	**1018**	**928**	**846**	**772**	**704**	**642**	**586**	**535**	**488**
Westspur Pipe Line Company – S. E. Sask. Light																				
Alida East – Alida, Unit	490	452	417	385	355	328	303	279	258	238	220	203	187	173	159	147	136	125	116	107
Carnduff – Midale East Unit	880	788	706	632	566	507	454	407	163	0	0	0	0	0	0	0	0	0	0	0
Elmore – Frobisher Vol. Unit	1240	1121	1015	918	831	752	680	615	557	504	456	412	373	337	305	276	250	226	204	185
Ingoldsby Frobisher Alida, Vol. Unit	970	843	746	668	606	554	510	473	440	412	388	366	346	328	312	298	285	273	262	251
Kenosee – Tilston, Vol. Unit	1650	1434	1247	1084	942	819	712	619	538	468	406	353	307	267	232	202	175	152	20	0
Parkman – Tilston Souris Valley	1250	1119	1003	898	805	721	646	578	518	464	416	151	0	0	0	0	0	0	0	0
Queensdale East-Frobisher Alida, Non Unit	2600	2376	2171	1984	1813	1657	1515	1384	1265	1156	1057	966	882	806	737	674	616	562	514	470
Rosebank – Frobisher Alida, Vol. Unit No. 1	1600	1363	1161	990	843	718	612	522	444	379	323	275	234	199	170	129	0	0	0	0
Steelman – Midale, Unit 1A	4340	4006	3698	3413	3151	2909	2685	2479	2288	2112	1950	1800	1661	1533	1416	1307	1206	1113	1028	949
Steelman – Midale, Unit II	3000	2741	2505	2290	2093	1912	1748	1597	1460	1334	1219	1114	1018	931	850	777	710	649	593	542
Steelman – Midale, Unit III	1725	1545	1384	1240	1110	995	891	798	715	640	574	514	460	412	369	331	296	265	238	213
Steelman – Midale, Unit IV	3000	2741	2505	2290	2093	1912	1748	1597	1460	1334	1219	1114	1018	931	850	777	710	649	593	542
Steelman – Midale, Unit VI	3485	3090	2741	2431	2156	1912	1696	1504	1334	1183	1049	930	825	732	649	576	510	453	401	356
Willmar – Frobisher Alida, Non Unit	1800	1620	1459	1313	1182	1064	958	863	777	699	629	567	510	459	413	372	335	302	213	0
Workman – Frobisher, Vol. Unit No. 1	1100	965	848	744	653	574	504	442	388	341	299	263	231	202	178	156	128	0	0	0
Other	19865	17876	16102	14517	13098	11826	10685	9659	8601	7686	6963	6160	5496	4990	4533	4110	3657	3256	2855	2468
Pipeline Total	**48995**	**44088**	**39714**	**35804**	**32305**	**29168**	**26353**	**23824**	**21213**	**18957**	**17173**	**15194**	**13556**	**12308**	**11182**	**10137**	**9020**	**8032**	**7042**	**6087**
Saskatchewan Total	**55915**	**50415**	**45501**	**41102**	**37156**	**33613**	**30429**	**27563**	**24645**	**22108**	**20069**	**17856**	**16005**	**14562**	**13256**	**12048**	**10782**	**9648**	**8361**	**7295**

LIGHT CRUDE OIL

MANITOBA

Trans-Prairie Pipelines Ltd.

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Daly – Mississippian	1240	1120	1013	915	827	748	676	611	552	499	451	408	369	333	301	272	246	222	201	13
Routledge - Mississippian	950	834	732	643	564	495	435	382	335	294	258	227	210	0	0	0	0	0	0	0
North Virden Scallion – Mississippian	5420	5008	4627	4276	3951	3651	3373	3117	2880	2662	2459	2272	2100	1940	1793	1657	1531	1414	1307	1208
Virden Roselea – Mississippian	2990	2782	2589	2409	2241	2086	1941	1806	1680	1564	1455	1354	1260	1172	1091	1015	944	879	818	761
Other	611	562	517	475	437	402	370	341	314	289	266	246	227	198	183	169	157	145	134	114
Pipeline Total	**11211**	**10308**	**9479**	**8720**	**8023**	**7384**	**6798**	**6259**	**5764**	**5310**	**4892**	**4508**	**4167**	**3645**	**3369**	**3115**	**2879**	**2662**	**2461**	**2097**
Manitoba Total	**11211**	**10308**	**9479**	**8720**	**8023**	**7384**	**6798**	**6259**	**5764**	**5310**	**4892**	**4508**	**4167**	**3645**	**3369**	**3115**	**2879**	**2662**	**2461**	**2097**

ONTARIO

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Ontario – Total	**1600**	**1463**	**1340**	**1229**	**1128**	**1038**	**955**	**880**	**813**	**751**	**694**	**643**	**596**	**553**	**513**	**477**	**444**	**414**	**386**	**360**

HEAVY CRUDE OIL

ALBERTA

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Bow River Pipe Lines Ltd.: Heavy																				
Bantry – Mannville A	5070	4605	4184	3801	3453	3137	2850	2589	2352	2136	1941	1763	1602	1455	1322	1201	1091	991	900	818
Countess – Upper Mannville D	5730	5056	4462	3938	3475	3067	2706	2388	2107	1860	1641	1448	1278	1128	995	878	775	684	603	532
Countess – Upper Mannville H	3730	3239	2813	2443	2122	1843	1600	1390	1207	1048	910	790	686	596	518	449	390	339	294	255
Grand Forks – Lower Mannville D	3000	9000	9000	8705	7556	6503	5597	4818	4147	3569	3072	2644	2275	1958	1686	1451	1249	1075	925	796
Hays – Lower Mannville A	1950	1680	1447	1247	1074	925	797	687	592	510	439	378	326	281	242	208	179	154	133	114
Lathom – Upper Mannville A	2550	2521	2189	1828	1527	1275	1065	890	743	621	518	433	361	302	252	210	176	147	122	67
Taber – Mannville D	2200	2200	2105	1819	1566	1348	1160	998	859	739	636	548	471	406	349	300	258	222	191	165
Taber South – Mannville B	1530	1241	1007	817	663	538	436	354	287	233	189	153	124	101	5	0	0	0	0	0
Other	14450	12739	11231	9901	8729	7695	6784	5981	5273	4649	4098	3613	3185	2808	2476	2182	1924	1696	1495	1318
Pipeline Total	**40210**	**42284**	**38441**	**34503**	**30168**	**26335**	**23000**	**20098**	**17570**	**15368**	**13448**	**11774**	**10313**	**9038**	**7848**	**6884**	**6045**	**5311**	**4668**	**4070**
BP Exploration Canada Limited																				
Chauvin – Mannville A	740	677	620	568	520	476	436	399	366	335	306	281	257	235	215	197	181	165	151	139
Chauvin South – Sparky A & B	1050	1050	1050	1038	966	892	824	760	702	648	598	552	509	470	434	401	370	341	315	291
Chauvin South – Sparky E	350	309	274	242	214	190	168	148	131	116	103	91	80	71	63	56	49	43	38	34
Chauvin South – Sparky H	290	288	263	233	207	183	162	144	128	113	100	89	79	70	62	55	49	43	38	34
Chauvin South – Lloydminster D	290	257	229	203	180	160	142	126	112	100	89	79	70	62	55	49	43	39	34	30
Other	865	822	775	727	665	605	551	502	458	418	381	347	317	289	264	241	220	201	184	168
Pipeline Total	**3585**	**3405**	**3212**	**3013**	**2755**	**2509**	**2286**	**2083**	**1899**	**1732**	**1579**	**1441**	**1315**	**1200**	**1096**	**1001**	**914**	**835**	**763**	**698**
Husky Pipeline Ltd. & Manito Pipelines Ltd.																				
Lloydminster – Sparky C and GP A	780	709	645	586	533	485	441	401	364	331	301	274	249	226	206	187	170	155	141	11
Lloydminster – Sparky and GP C	2000	1912	1730	1566	1417	1282	1160	1049	949	859	777	703	636	576	521	471	426	386	349	316
Viking Kinsella – Wainwright B	4500	7000	9449	8423	7177	6116	5212	4441	3784	3225	2748	2341	1995	1700	1449	1234	1052	896	764	651
Wainwright – Wainwright & Sparky A	6740	7100	7048	6525	5933	5396	4907	4462	4058	3690	3355	3051	2775	2523	2294	2086	1897	1725	1569	1427
Wildmere – Lloydminster A & Sparky B	2200	2466	2733	3000	2869	2609	2372	2157	1962	1784	1622	1475	1341	1220	1109	1009	917	834	758	690
Other	4000	4982	4430	3719	3122	2620	2200	1846	1550	1301	1092	917	769	597	0	0	0	0	0	0
Pipeline Total	**20220**	**24171**	**26038**	**23820**	**21053**	**18510**	**16293**	**14359**	**12670**	**11192**	**9898**	**8764**	**7768**	**6844**	**5581**	**4990**	**4465**	**3998**	**3582**	**3096**

HEAVY CRUDE OIL

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Truck and Tank Car																				
Cessford – Total	3200	3148	2832	2512	2228	1976	1752	1554	1378	1222	1084	961	853	756	671	595	527	468	415	368
Other	2350	2348	2232	2060	1902	1755	1620	1496	1381	1275	1177	1086	1003	925	854	789	728	672	620	572
Pipeline Total	**5550**	**5496**	**5064**	**4572**	**4130**	**3732**	**3373**	**3050**	**2760**	**2497**	**2261**	**2048**	**1856**	**1682**	**1525**	**1384**	**1256**	**1140**	**1035**	**941**
Alberta Total	**69565**	**75359**	**72757**	**65910**	**58108**	**51087**	**44954**	**39592**	**34900**	**30791**	**27189**	**24029**	**21254**	**18766**	**16052**	**14260**	**12682**	**11287**	**10051**	**8806**
SASKATCHEWAN																				
Husky Pipeline Ltd. & Manito Pipelines Ltd.																				
Aberfeldy – Sparky, Aberfeldy Unit	4350	3751	3235	2790	2406	2075	1789	1543	1331	1148	990	853	736	635	547	472	407	351	10	0
South Aberfeldy – Sparky, Voluntary Unit	1830	1614	1425	1257	1109	979	864	762	673	594	524	462	408	360	318	280	247	218	151	0
Dulwich – Sparky	700	648	601	557	516	478	443	411	381	353	327	303	281	260	241	223	207	192	31	0
Epping – Sparky and G.P., Non-unit	1860	1583	1347	1147	976	831	707	602	513	436	371	316	43	0	0	0	0	0	0	0
South Epping – Sparky and G.P., Unit No. 1	2050	1843	1658	1491	1341	1206	1085	976	877	789	710	638	574	516	464	418	376	338	304	273
S.W. Epping Sparky Vol. Unit No. 1	990	885	792	709	635	568	508	455	407	364	326	291	261	233	209	86	0	0	0	0
Furness – Sparky	500	423	358	302	256	216	183	155	131	111	69	0	0	0	0	0	0	0	0	0
Golden Lake North – Waseca & Sparky, Vol. Unit	2030	1738	1488	1275	1092	935	800	685	587	503	430	368	316	270	231	144	0	0	0	0
Golden Lake North – Waseca & Sparky, Non-Unit	830	707	602	513	437	372	317	270	230	196	167	112	0	0	0	0	0	0	0	0
Golden Lake South – Sparky	510	466	425	389	355	325	297	271	248	226	207	189	173	158	144	132	120	110	100	10
Golden Lake South – Waseca	1910	1576	1300	1073	886	731	603	498	411	339	280	231	190	157	129	107	39	0	0	0
Gully Lake – Waseca, Vol. Unit No. 1	900	813	735	664	600	543	490	443	401	362	327	296	267	242	218	187	0	0	0	0
Gully Lake – Waseca, Non-Unit	720	616	528	452	387	331	284	243	208	178	152	130	112	79	0	0	0	0	0	0
Lashburn – Waseca, Vol. Unit	610	535	470	413	362	318	279	245	215	189	166	126	0	0	0	0	0	0	0	0
Lone Rock – Sparky	230	200	174	152	132	115	101	8	0	0	0	0	0	0	0	0	0	0	0	0
Tangleflags (Total	2840	2379	1993	1669	1399	1172	981	822	689	577	483	405	339	284	238	199	167	140	117	99
Other	7340	6009	4920	4028	3298	2700	2210	1810	1481	1213	993	813	665	86	0	0	0	0	0	0
Pipeline Total	**30200**	**25794**	**22059**	**18889**	**16195**	**13903**	**11951**	**10207**	**8789**	**7584**	**6529**	**5542**	**4370**	**3285**	**2744**	**2252**	**1566**	**1351**	**715**	**383**

HEAVY CRUDE OIL

Bow River Pipe Lines Ltd. (Heavy Blend)

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Coleville – Bakken	4225	3896	3593	3313	3055	2817	2598	2396	2210	2038	1879	1733	1598	1474	1359	1253	1156	1066	983	906
North Hoosier – Bakken, Vol. Unit	980	980	945	856	775	701	634	574	519	470	425	385	348	315	285	258	233	211	191	173
North Hoosier – Basal Blairmore, Vol. Unit	510	455	407	364	325	291	260	232	208	186	166	148	133	118	106	95	84	45	0	0
Other – Heavy	1050	936	835	745	665	593	529	472	421	376	335	299	267	238	212	189	169	151	134	120
Smiley Dewar – Viking (100%)	1940	1841	1748	1659	1575	1495	1420	1348	1279	1214	1153	1094	1039	986	936	889	844	801	760	722
Plato-Viking (100%)	220	209	199	189	180	172	163	156	148	141	134	128	122	116	110	105	100	95	91	86
Dodsland - Viking, Eagle Lake Vol. Unit (27%)	390	367	346	326	308	290	273	258	243	229	216	203	192	181	170	160	151	143	134	127
Dodsland – Viking, Gleneath Unit (27%)	340	319	299	281	264	248	232	218	205	192	181	170	159	149	140	132	124	116	109	102
Eureka – Viking, South Unit (27%)	210	192	177	162	149	137	126	115	106	97	89	82	75	69	63	58	43	0	0	0
Other – Light (27%)	556	494	439	390	346	308	273	243	216	192	170	151	134	119	106	94	84	69	0	0
Pipeline Total	**10421**	**9694**	**8993**	**8291**	**7647**	**7056**	**6514**	**6016**	**5559**	**5139**	**4753**	**4398**	**4071**	**3770**	**3493**	**3237**	**2992**	**2700**	**2405**	**2238**

South Saskatchewan Pipe Line Company

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Battrum – Roseray, Unit No. 1	2450	2307	2172	2046	1927	1815	1709	1609	1516	1427	1344	1266	1192	1123	1057	996	938	883	832	783
Cantuar Main – Cantuar, Unit	1905	1728	1569	1424	1292	1172	1064	966	876	795	722	655	594	539	489	444	403	366	332	301
Dollard – Upper Shaunavon, Unit	7600	6373	5344	4482	3758	3152	2643	2216	1859	1559	1307	1096	919	771	646	542	454	29	0	0
Fosterton – Roseray, Main Unit	4025	3682	3368	3081	2819	2579	2359	2158	1974	1806	1652	1512	1383	1265	1157	1059	969	886	811	741
Gull Lake North – Upper Shaunavon, Unit	1450	1278	1127	993	875	772	680	600	529	466	411	362	319	281	97	0	0	0	0	0
Instow – Upper Shaunavon, Unit	3900	3525	3186	2880	2603	2353	2127	1923	1738	1571	1420	1283	1160	1049	948	857	774	700	633	572
Main Success – Roseray, Unit	740	621	522	439	368	310	260	218	54	0	0	0	0	0	0	0	0	0	0	0
North Premier – Roseray, Unit No. 3	1280	1050	861	706	579	475	390	320	262	215	176	144	118	47	0	0	0	0	0	0
Rapdan – Upper Shaunavon, Unit	1650	1515	1392	1278	1174	1078	990	910	835	767	705	647	594	546	501	461	423	388	357	328
South Success – Roseray, Unit	1420	1293	1178	1074	978	891	812	740	674	614	560	510	465	423	386	351	320	292	266	242
Suffield – Upper Shaunavon, Unit No. 2	950	950	943	864	774	693	621	556	498	446	400	358	321	287	257	230	206	185	165	148
Verlo – Roseray, Unit	2160	1860	1603	1381	1190	1025	883	761	655	565	486	419	361	311	268	231	199	171	147	120
Other	23840	21144	18753	16632	14751	13083	11604	10291	9128	8095	7180	6368	5648	5009	4443	3940	3495	3099	2749	2305
Pipeline Total	**53370**	**47332**	**42023**	**37285**	**33095**	**29404**	**26148**	**23274**	**20604**	**18332**	**16368**	**14626**	**13080**	**11657**	**10255**	**9115**	**8185**	**7004**	**6295**	**5544**

HEAVY CRUDE OIL

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Westspur Pipe Line Company – S.E. Sask. Medium																				
Benson – Midale, Unit	1090	999	915	839	769	705	646	592	543	498	456	418	383	351	322	295	270	248	227	208
Innes – Frobisher	1300	1200	1107	1022	943	871	804	742	685	632	584	539	497	459	424	391	361	333	308	284
Lost Horse Hill – Frobisher Alida Vol. Unit No. 1	1400	1217	1058	919	799	695	604	525	456	397	345	300	260	226	197	171	149	129	112	97
Midale – Central Midale, Unit	8000	7414	6871	6368	5902	5470	5070	4699	4355	4036	3741	3467	3213	2978	2760	2558	2371	2197	2036	1887
Midale – Central Midale, Non-Unit	800	702	616	541	475	417	366	322	282	253	0	0	0	0	0	0	0	0	0	0
Viewfield – Frobisher	1050	969	894	825	762	703	649	599	553	511	471	435	402	371	342	316	291	269	248	229
Weyburn – Midale, Unit	21660	20378	19172	18037	16970	15966	15021	14132	13296	12509	11768	11072	10417	9800	9220	8675	8161	7678	7224	6796
Weyburn – Midale, Non-Unit	810	718	637	565	501	444	394	349	310	275	243	216	191	170	150	133	116	0	0	0
Other	8300	7623	7002	6431	5907	5426	4984	4577	4204	3862	3547	3258	2992	2749	2525	2319	2130	1956	1797	1650
Pipeline Total	**44410**	**41222**	**38277**	**35553**	**33033**	**30701**	**28542**	**26542**	**24688**	**22975**	**21159**	**19708**	**18360**	**17107**	**15943**	**14861**	**13853**	**12814**	**11955**	**11156**
Saskatchewan Total	**138401**	**124044**	**111354**	**100020**	**89972**	**81065**	**73156**	**66040**	**59642**	**54032**	**48810**	**44275**	**39882**	**35821**	**32437**	**29467**	**26597**	**23870**	**21371**	**19323**
Canada – Total Light Crude Oil	**1507701**	**1431231**	**1326599**	**1190920**	**1046008**	**915239**	**800550**	**701371**	**616354**	**543377**	**480834**	**426257**	**379394**	**338601**	**303335**	**272683**	**245340**	**221268**	**199590**	**180468**
Canada – Total Heavy Crude Oil	**207966**	**199403**	**184110**	**165930**	**148080**	**132153**	**118111**	**105633**	**94543**	**84823**	**76000**	**68304**	**61137**	**54588**	**48489**	**43728**	**39280**	**35157**	**31423**	**28130**
Canada – Total Crude Oil	**1715667**	**1630634**	**1510709**	**1356850**	**1194088**	**1047392**	**918661**	**807004**	**710897**	**628200**	**556834**	**494561**	**440531**	**393189**	**351824**	**316411**	**284620**	**256424**	**231013**	**208598**

PENTANES PLUS PRODUCTION
NEB Forecast
b/d

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
From Established Reserves																				
British Columbia																				
Total	**3090**	**3000**	**3000**	**2900**	**2900**	**2800**	**2700**	**2400**	**2200**	**2000**	**1900**	**1800**	**1700**	**1600**	**1500**	**1400**	**1300**	**1200**	**1100**	**1000**
Alberta																				
Bow River Pipe Lines																				
Empress (Pacific)	2150	2125	2100	2080	2050	2020	2000	1975	1950	1950	1950	1950	1950	1950	1750	1625	1515	1425	1270	1165
Others	780	744	708	667	616	582	536	502	467	412	385	361	337	320	304	296	270	252	236	230
Total	**2930**	**2869**	**2808**	**2747**	**2666**	**2602**	**2536**	**2477**	**2417**	**2362**	**2335**	**2311**	**2287**	**2270**	**2054**	**1921**	**1785**	**1677**	**1506**	**1395**
Co-ed Pipe Line																				
Cochrane	1350	1455	1500	1500	1500	1500	1425	1345	1285	1245	1140	1030	950	835	715	645	525	455	400	325
Empress (Dome)	1850	1830	1780	1685	1740	1665	1485	1295	1070	875	675	460	265	50	0	0	0	0	0	0
Minnehik-Buck Lake	1116	1120	1124	1097	1071	1038	923	805	704	618	543	478	421	371	328	290	256	227	201	178
Quirk Creek	852	839	758	661	578	507	446	394	348	308	274	243	216	192	171	153	136	122	109	97
Ricinus	2468	2285	2106	1930	1759	1594	1436	1235	611	605	599	594	588	583	574	534	489	449	412	376
Strachan (Aquitaine)	1380	1325	1192	1062	950	809	684	581	495	423	362	311	267	229	195	162	139	120	103	89
Strachan (Gulf)	5850	5744	4992	4303	3716	3215	2785	2414	2094	1818	1578	1371	1191	1035	899	782	679	591	513	446
Others	1282	1218	1132	1039	939	848	749	673	601	512	446	390	342	298	262	231	201	173	156	127
Total	**16148**	**15816**	**14584**	**13277**	**12253**	**11176**	**9933**	**8792**	**7208**	**6404**	**5617**	**4877**	**4240**	**3593**	**3144**	**2797**	**2425**	**2137**	**1894**	**1640**
Cremona Pipeline																				
Carstairs (Home)	4474	4398	4087	3773	3255	2757	2330	1968	1663	1406	1191	1010	858	730	622	531	454	388	333	286
Crossfield	2257	2049	1859	1687	1532	1392	1266	1152	1049	956	872	796	727	665	608	555	507	466	428	393
Harmattan	5754	5546	5347	5156	4973	4798	2975	2747	2446	2093	1792	1536	1317	1131	971	835	718	617	531	457
Olds	551	499	453	411	374	341	311	284	260	238	218	200	184	169	156	144	133	123	113	105
Others	2101	1997	1855	1704	1539	1389	1228	1104	985	839	733	640	561	489	429	378	330	284	255	209
Total	**15137**	**14489**	**13601**	**12731**	**11673**	**10677**	**8110**	**7255**	**6403**	**5532**	**4806**	**4182**	**3647**	**3184**	**2786**	**2443**	**2142**	**1878**	**1660**	**1450**
Federated Pipe Lines																				
Others	105	100	93	85	77	70	62	55	49	42	37	33	28	25	22	19	17	14	13	10
Gibson Petroleum																				
Others	861	839	801	769	740	688	654	620	584	530	465	414	377	336	265	203	184	161	132	93
Gulf Alberta Pipe Line																				
Nevis	2256	2201	2117	1799	1496	1243	1030	854	544	569	489	422	365	307	244	214	188	165	146	0
Others	775	759	742	727	714	702	686	671	657	645	613	584	555	529	506	472	457	433	421	404
Total	**3031**	**2960**	**2859**	**2526**	**2210**	**1945**	**1716**	**1525**	**1201**	**1214**	**1102**	**1006**	**920**	**836**	**750**	**686**	**645**	**598**	**567**	**404**

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Alberta Continued																				
Imperial Pipe Line – Ellerslie																				
Others	478	456	424	394	362	316	284	251	224	193	167	146	128	111	98	86	75	65	58	49
Imperial Pipe Line – Leduc																				
Judy Creek	6533	6666	6725	6473	5980	5288	4666	4118	3637	3213	2840	2511	2221	1966	1741	1542	1366	1211	1074	953
Leduc Woodbend	436	440	433	412	381	344	305	267	217	178	362	383	407	389	374	361	356	303	303	303
Total	**6969**	**7106**	**7158**	**6885**	**6361**	**5632**	**4971**	**4385**	**3854**	**3391**	**3202**	**2894**	**2628**	**2355**	**2115**	**1903**	**1722**	**1514**	**1377**	**1256**
Imperial Pipe Line – Redwater																				
Redwater	560	616	600	462	356	275	212	163	126	97	75	57	44	34	0	0	0	0	0	0
Murphy Oil																				
Others	80	78	75	71	69	66	64	61	59	57	55	54	52	50	49	44	39	36	33	30
Peace River Oil Pipe Line																				
Carson Creek	1998	2032	2013	1991	1971	1844	1662	1501	1314	1128	971	838	724	627	545	474	413	360	314	275
Dunvegan	1370	1512	1506	1501	1497	1493	1489	1486	1366	1165	993	847	722	616	525	445	374	319	272	231
Gold Creek	1003	918	840	768	703	631	564	506	453	407	365	328	294	265	229	198	179	162	147	0
Kaybob	460	461	458	456	456	434	386	342	303	268	238	211	188	167	149	133	119	106	95	85
Kaybob South	42818	39338	36072	33005	30120	27414	24871	22482	20244	15672	13220	11168	9457	8031	6833	5822	4967	4243	3627	3104
Simonette (Shell)	696	815	935	972	997	914	833	765	709	623	527	446	377	319	270	229	194	0	0	0
Windfall	4709	4134	3573	3028	2499	1984	1485	735	575	453	360	287	230	186	150	122	99	81	67	55
Others	885	842	782	718	649	585	518	465	416	354	309	270	236	206	181	159	139	120	107	88
Total	**53939**	**50052**	**46179**	**42439**	**38892**	**35299**	**31808**	**28282**	**25380**	**20070**	**16983**	**14395**	**12228**	**10417**	**8882**	**7582**	**6484**	**5391**	**4629**	**3838**
Pembina Pipe Line																				
Brazeau (Tenneco)	499	478	459	422	370	326	288	256	227	203	181	162	146	131	118	106	96	87	79	71
Brazeau (HBOG)	1923	1890	1810	1712	1591	1487	1396	1316	1245	1182	1125	1074	1008	887	778	685	604	533	471	417
Pembina (Goliad)	821	718	637	571	516	471	432	399	370	344	322	302	285	269	255	242	230	219	209	200
Others	900	834	742	656	584	501	426	405	385	364	347	321	313	298	281	269	253	238	228	204
Total	**4143**	**3920**	**3648**	**3361**	**3061**	**2785**	**2542**	**2376**	**2227**	**2093**	**1975**	**1859**	**1752**	**1585**	**1432**	**1302**	**1183**	**1077**	**987**	**892**
Rainbow Pipe Line																				
Mitsue (Chevron)	533	542	542	520	467	418	375	335	301	269	241	216	193	173	155	139	124	112	100	89
Others	380	390	380	375	360	307	261	226	187	164	132	111	98	84	73	64	58	52	41	31
Total	**913**	**932**	**922**	**895**	**827**	**725**	**636**	**561**	**488**	**433**	**373**	**327**	**291**	**257**	**228**	**203**	**182**	**164**	**141**	**120**

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Alberta (Concluded)																				
Rangeland Pipe Line																				
Ferrier	1496	1480	1465	1452	1379	1219	1077	952	841	743	656	580	512	452	400	353	312	276	244	215
Gilby	1207	1158	1083	1016	957	897	843	801	758	725	674	597	512	444	385	327	285	244	177	150
Pincher Creek	1833	1526	1276	1072	905	766	651	556	475	408	351	303	262	226	196	171	139	96	83	0
Waterton	11430	10440	9077	8366	7403	7141	7218	7279	7323	6805	5898	5167	4574	4091	3695	3310	2845	2445	2106	1818
Wimborne	1365	1351	1294	1096	920	772	649	545	458	385	324	271	226	0	0	0	0	0	0	0
Others	2237	2126	1975	1814	1639	1479	1308	1175	1049	894	780	681	597	520	458	403	351	302	271	222
Total	**19568**	**18081**	**16170**	**14816**	**13203**	**12274**	**11746**	**11308**	**10904**	**9960**	**8683**	**7599**	**6683**	**5733**	**5134**	**4564**	**3932**	**3363**	**2881**	**2405**
Rimbey Pipeline																				
Homeglen Rimbey	8683	8646	8231	7341	6137	5052	4141	3394	2797	2321	1939	1634	1389	1193	1036	900	788	671	460	345
Texaco Exploration																				
Bonnie Glen	3743	4016	4289	4405	4517	4341	3937	3505	3164	2893	1907	1831	1792	1754	1741	1738	1594	1386	1233	1122
Others	120	113	105	97	87	79	70	63	56	48	42	36	32	28	25	22	20	16	15	12
Total	**3863**	**4129**	**4394**	**4502**	**4604**	**4420**	**4007**	**3568**	**3220**	**2941**	**1949**	**1867**	**1824**	**1782**	**1766**	**1760**	**1614**	**1402**	**1248**	**1134**
Valley Pipe Line																				
Jumping Pound	2335	2370	2404	2389	2349	2312	2277	2243	2212	2171	2114	2061	1987	1890	1804	1670	1483	1318	1173	1044
Wildcat Hills	673	664	657	648	616	558	505	457	413	374	338	306	277	250	227	205	186	168	152	137
Others	475	420	394	371	354	339	322	298	275	239	202	164	122	79	24	0	0	0	0	0
Total	**3483**	**3454**	**3455**	**3408**	**3319**	**3209**	**3104**	**2998**	**2900**	**2784**	**2654**	**2531**	**2386**	**2219**	**2055**	**1875**	**1669**	**1486**	**1325**	**1181**
Truck & Tank Car																				
Edson	2093	2158	1965	1710	1492	1299	1132	989	865	758	665	585	514	453	399	353	311	275	241	200
Others	764	727	675	621	564	506	447	402	363	301	271	237	208	179	159	144	120	103	97	79
Total	**2857**	**2885**	**2640**	**2331**	**2056**	**1805**	**1579**	**1391**	**1228**	**1059**	**936**	**822**	**722**	**632**	**558**	**497**	**431**	**378**	**338**	**279**
Alberta Total	**143748**	**137428**	**128642**	**119040**	**108866**	**99016**	**88105**	**79462**	**71269**	**61483**	**53353**	**47008**	**41626**	**36612**	**32374**	**28785**	**25317**	**22012**	**19249**	**16521**
Saskatchewan																				
Total	**790**	**696**	**612**	**539**	**474**	**417**	**367**	**323**	**284**	**250**	**220**	**193**	**170**	**150**	**132**	**116**	**102**	**90**	**79**	**69**
Total Canada	147628	141124	132254	122479	112240	102233	91172	82185	73753	63733	55473	49001	43496	38362	34006	30301	26719	23302	20428	17590
Less Injection	2750	2750	2500	2250	2000	1750	1500	1250	1000	0	0	0	0	0	0	0	0	0	0	0
Available Total	144878	138374	129754	120229	110240	100483	89672	80935	72753	63733	55473	49001	43496	38362	34006	30301	26719	23302	20428	17590
From Reserves Additions	0	1668	3752	6655	10179	14213	17556	20229	22275	23678	24491	26054	27259	28141	28733	28855	28580	28029	27291	26413
Total Canada	**144878**	**140042**	**133506**	**126884**	**120419**	**114696**	**107228**	**101164**	**95028**	**87411**	**79964**	**75055**	**70755**	**66503**	**62739**	**59156**	**55299**	**51331**	**47719**	**44003**

POTENTIAL PRODUCIBILITY FROM OIL SANDS
NEB Forecast Mb/d

MAXIMUM CASE

	Experi-mental In-Situ	GCOS	Syncrude	Syncrude Expansion	3rd Mining	1st In-Situ	4th Mining	5th Mining	2nd In-Situ	6th Mining	Total
1976	5	50	–	–	–	–	–	–	–	–	55
1977	6	50	–	–	–	–	–	–	–	–	56
1978	8	55	25	–	–	–	–	–	–	–	88
1979	9	60	90	–	–	–	–	–	–	–	159
1980	10	65	105	–	–	–	–	–	–	–	180
1981	12	65	105	–	–	–	–	–	–	–	182
1982	14	65	115	–	–	–	–	–	–	–	194
1983	16	65	120	–	–	–	–	–	–	–	201
1984	18	65	125	–	–	–	–	–	–	–	208
1985	20	65	125	–	25	–	–	–	–	–	235
1986	20	65	125	20	75	–	–	–	–	–	305
1987	20	65	125	50	100	25	–	–	–	–	385
1988	20	65	125	60	100	50	–	–	–	–	420
1989	20	65	125	75	100	75	60	–	–	–	520
1990	20	65	125	75	100	100	90	–	–	–	575
1991	20	65	125	75	100	100	120	50	–	–	655
1992	20	65	125	75	100	100	120	100	–	–	705
1993	20	65	125	75	100	100	120	125	25	–	755
1994	20	65	125	75	100	100	120	125	50	–	780
1995	20	65	125	75	100	100	120	125	75	50	855

EXPECTED CASE

	Experi-mental In-Situ	CGOS	Syncrude	Syncrude Expansion	3rd Mining	1st In-Situ	4th Mining	5th Mining	2nd In-Situ	6th Mining	Total
1976	5	50	–	–	–	–	–	–	–	–	55
1977	5	50	–	–	–	–	–	–	–	–	55
1978	5	50	–	–	–	–	–	–	–	–	55
1979	5	55	50	–	–	–	–	–	–	–	110
1980	6	60	90	–	–	–	–	–	–	–	156
1981	8	65	105	–	–	–	–	–	–	–	178
1982	10	65	105	–	–	–	–	–	–	–	180
1983	10	65	115	–	–	–	–	–	–	–	190
1984	10	65	120	–	–	–	–	–	–	–	195
1985	15	65	125	–	–	–	–	–	–	–	205
1986	15	65	125	–	–	–	–	–	–	–	205
1987	15	65	125	(*)	25	–	–	–	–	–	230
1988	15	65	125	(*)	75	–	–	–	–	–	280
1989	15	65	125	(*)	100	25	–	–	–	–	330
1990	15	65	125	(*)	100	50	–	–	–	–	355
1991	15	65	125	(*)	100	75	60	–	–	–	440
1992	15	65	125	(*)	100	100	90	–	–	–	495
1993	15	65	125	(*)	100	100	120	–	–	–	525
1994	15	65	125	(*)	100	100	120	–	25	–	550
1995	15	65	125	(*)	100	100	120	–	50	–	575

* Syncrude expansion or third mining plant considered to have equal probability, but only one at a time.

MINIMUM CASE

	Experi-mental In-Situ	GCOS	Syncrude	Syncrude Expansion	3rd Mining	1st In-Situ	4th Mining	5th Mining	2nd In-Situ	6th Mining	Total
1976	5	50	–	–	–	–	–	–	–	–	55
1977	5	50	–	–	–	–	–	–	–	–	55
1978	5	50	–	–	–	–	–	–	–	–	55
1979	5	50	50	–	–	–	–	–	–	–	105
1980	6	50	90	–	–	–	–	–	–	–	146
1981	8	50	105	–	–	–	–	–	–	–	163
1982	10	50	105	–	–	–	–	–	–	–	165
1983	10	50	115	–	–	–	–	–	–	–	175
1984	8	50	120	–	–	–	–	–	–	–	178
1985	6	50	125	–	–	–	–	–	–	–	181
1986	5	50	125	–	–	–	–	–	–	–	180
1987	5	50	125	–	–	–	–	–	–	–	180
1988	5	50	125	–	–	–	–	–	–	–	180
1989	5	50	125	–	–	–	–	–	–	–	180
1990	5	50	125	–	–	–	–	–	–	–	180
1991	5	50	125	–	–	–	–	–	–	–	180
1992	5	50	125	–	–	–	–	–	–	–	180
1993	5	50	125	–	–	–	–	–	–	–	180
1994	5	50	125	–	–	–	–	–	–	–	180
1995	5	50	125	–	–	–	–	–	–	–	180

POTENTIAL PRODUCIBILITY OF CRUDE OIL AND EQUIVALENT
Summary of NEB Forecasts
Mb/d

	LIGHT CRUDE OIL AND EQUIVALENT					HEAVY CRUDE OIL					TOTAL CRUDE OIL AND EQUIVALENT				
	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands (Synthetic)	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Total
1976	1508	—	137	50	1695	208	—	8	5	221	1716	—	145	55	1916
1977	1431	4	131	50	1616	200	7	9	5	221	1631	11	140	55	1837
1978	1327	7	124	50	1508	184	20	9	5	218	1511	27	133	55	1726
1979	1191	15	118	105	1429	166	31	9	5	211	1357	46	127	110	1640
1980	1046	22	111	150	1329	148	41	9	6	204	1194	63	120	156	1533
1981	915	31	106	170	1222	132	49	9	8	198	1047	80	115	178	1420
1982	801	38	98	170	1107	118	57	9	10	194	919	95	107	180	1301
1983	701	47	92	180	1020	106	63	9	10	188	807	110	101	190	1208
1984	616	55	86	185	942	95	69	9	10	183	711	124	95	195	1125
1985	543	63	78	190	874	85	74	9	15	183	628	137	87	205	1057
1986	481	72	71	190	814	76	78	9	15	178	557	150	80	205	992
1987	426	80	66	215	787	68	81	9	15	173	494	161	75	230	960
1988	379	88	62	265	794	61	84	9	15	169	440	172	71	280	963
1989	338	95	58	315	806	55	86	9	15	165	393	181	67	330	971
1990	303	101	54	340	798	49	88	9	15	161	352	189	63	355	959
1991	273	106	50	425	854	44	89	9	15	157	317	195	59	440	1011
1992	245	109	46	480	880	39	90	9	15	153	284	199	55	495	1033
1993	221	112	42	510	885	35	90	9	15	149	256	202	51	525	1034
1994	200	114	39	535	888	31	90	9	15	145	231	204	48	550	1033
1995	181	114	35	560	890	28	90	9	15	142	209	204	44	575	1032

TOTAL ENERGY AND OIL DEMAND BY SECTOR
NEB Forecast

Trillions of Btu's

	1974 (actual)	1976	1977	1978	1979	1980	1985	1990	1995
Residential									
Total Oil	**608.2**	**566.9**	**564.4**	**561.6**	**558.9**	**555.6**	**538.1**	**529.2**	**519.9**
Kerosene	73.1	67.3	67.1	67.1	67.0	66.9	66.0	66.1	66.3
Diesel	45.0	44.5	44.8	44.9	45.0	44.8	44.1	44.1	44.1
Light Fuel Oil	456.0	423.1	420.9	418.4	416.1	413.4	398.9	390.9	382.6
Heavy Fuel Oil	34.1	32.0	31.6	31.2	30.8	30.5	29.1	28.1	26.9
Total Energy	**1176.2**	**1167.4**	**1186.2**	**1202.7**	**1220.2**	**1229.5**	**1292.1**	**1394.3**	**1507.3**
Commercial									
Total Oil	**258.5**	**256.7**	**261.1**	**263.3**	**265.1**	**266.7**	**288.4**	**312.8**	**332.5**
Kerosene	7.5	7.8	7.8	7.8	7.7	7.6	8.1	8.7	9.2
Diesel	21.3	20.1	20.1	20.0	19.8	19.7	20.7	23.3	25.7
Light Fuel Oil	77.1	84.2	85.8	86.6	87.3	87.9	94.6	101.9	107.4
Heavy Fuel Oil	152.6	144.6	147.4	148.9	150.3	151.5	165.0	178.9	190.2
Total Energy	**766.5**	**820.8**	**853.5**	**880.1**	**906.7**	**932.4**	**1092.0**	**1295.0**	**1524.9**
Industrial									
Total Oil	**525.2**	**518.6**	**554.2**	**569.0**	**576.6**	**584.0**	**675.5**	**802.7**	**958.5**
Kerosene	11.1	17.7	18.3	18.7	19.0	19.3	22.4	26.7	31.9
Diesel	114.6	123.1	129.7	136.9	139.1	141.2	163.9	196.1	235.7
Light Fuel Oil	78.8	86.4	89.2	91.0	92.4	93.8	108.6	129.1	154.3
Heavy Fuel Oil	320.7	291.4	317.0	322.4	326.1	329.7	380.6	450.8	536.6
Total Energy*	**1677.8**	**1770.2**	**1835.5**	**1882.8**	**1919.9**	**1951.7**	**2273.7**	**2692.3**	**3210.7**
Petrochemical									
Total Oil	**84.9**	**83.9**	**149.3**	**179.8**	**189.6**	**235.9**	**244.4**	**347.1**	**450.1**
Total Energy	**164.1**	**187.6**	**275.2**	**340.5**	**370.8**	**428.6**	**480.6**	**602.8**	**729.6**

*Includes coal used to produce coke and coke oven gas, and excludes requirements for the production of petrochemicals.

Trillions of Btu's

	1974 (actual)	1976	1977	1978	1979	1980	1985	1990	1995
Transportation									
ROAD									
Total Oil	**1171.7**	**1246.3**	**1294.8**	**1328.6**	**1360.6**	**1388.3**	**1454.4**	**1425.0**	**1443.4**
Motor Gasoline	1087.7	1156.5	1197.8	1223.9	1247.5	1266.1	1291.2	1220.3	1215.0
Diesel	84.0	89.8	97.0	104.7	113.1	122.2	163.2	204.7	228.4
Total Energy	**1171.7**	**1246.3**	**1294.8**	**1328.6**	**1360.6**	**1388.3**	**1454.4**	**1425.0**	**1443.4**
RAIL									
Total Oil	**100.4**	**102.1**	**106.6**	**110.3**	**113.7**	**116.4**	**134.7**	**150.5**	**169.2**
Kerosene	1.1	1.3	1.4	1.5	1.5	1.5	1.8	2.0	2.3
Diesel	88.9	89.2	93.2	96.5	99.6	102.1	118.6	133.2	150.5
Light Fuel Oil	2.9	2.2	2.3	2.3	2.4	2.5	2.9	3.3	3.7
Heavy Fuel Oil	7.5	9.4	9.7	10.0	10.2	10.3	11.4	12.0	12.7
Total Energy	**101.4**	**103.4**	**107.9**	**111.6**	**115.0**	**117.8**	**136.0**	**151.8**	**170.5**
AIR									
Total Oil	**131.2**	**139.0**	**146.5**	**153.5**	**164.5**	**173.5**	**226.0**	**268.1**	**317.5**
Aviation Gasoline	7.4	8.0	8.2	8.5	8.7	8.9	8.9	10.5	12.4
Aviation Turbo Fuel	123.8	131.0	138.3	145.0	155.8	164.6	217.1	257.6	305.1
Total Energy	**131.2**	**139.0**	**146.5**	**153.5**	**164.5**	**173.5**	**226.0**	**268.1**	**317.5**
MARINE									
Total Oil	**111.9**	**108.4**	**112.8**	**125.1**	**136.9**	**148.0**	**169.7**	**187.8**	**208.1**
Kerosene	.3	.3	.3	.3	.3	.4	.4	.5	.6
Diesel	40.1	44.2	46.3	48.1	49.8	51.2	59.7	67.3	75.9
Light Fuel Oil	1.3	.5	.6	.6	.6	.6	.7	.7	.8
Heavy Fuel Oil	70.2	63.4	65.6	76.1	86.2	95.8	108.9	119.3	130.8
Total Energy	**114.3**	**111.6**	**116.1**	**128.4**	**140.2**	**151.2**	**172.9**	**190.6**	**210.4**

Export Formula Case

Trillions of Btu's

	1976	1980	1985	1990	1995
Residential					
Total Oil	578.5	606.4	619.5	608.8	595.9
Total Energy	1187.2	1337.2	1485.5	1601.0	1723.7
Commercial					
Total Oil	263.5	296.8	336.8	358.4	373.5
Total Energy	836.4	1018.7	1248.3	1454.1	1679.9
Industrial					
Total Oil	534.0	670.1	838.8	1003.3	1198.2
Total Energy	1816.2	2219.6	2794.0	3338.6	3991.3
Petrochemicals					
Total Oil	83.9	235.9	244.4	347.1	450.1
Total Energy	187.6	428.6	480.6	602.8	729.6
Transportation					
Road					
Total Oil	1269.0	1598.6	2002.3	2232.6	2353.1
Total Energy	1269.0	1598.6	2002.3	2232.6	2353.1
Rail					
Total Oil	102.1	116.5	134.7	150.5	169.2
Total Energy	103.4	117.8	136.0	151.8	170.5
Air					
Total Oil	139.8	175.3	230.1	275.1	328.4
Total Energy	139.8	175.3	230.1	275.1	328.4
Marine					
Total Oil	108.4	148.0	169.8	187.9	208.1
Total Energy	111.7	151.2	172.9	190.6	210.4

PETROLEUM PRODUCT DEMAND
NEB Forecast and NEB Export Formula Case

CANADA
Mb/d

	1975*	1976	1977	1978	1979	1980	1985	1990	1995
NEB Forecast									
Motor Gasoline	595.3	606.6	628.5	642.2	654.5	664.2	677.4	640.3	637.5
Light Fuel Oil, Kerosene and Stove Oil	321.4	327.7	328.9	329.3	329.5	329.1	334.3	346.1	360.2
Diesel Fuel Oil	188.0	199.9	209.6	219.5	227.0	234.6	278.4	327.3	374.6
Heavy Fuel Oil	270.5	297.0	328.7	348.1	359.4	362.6	424.6	441.9	486 8
Petrochemical Feedstock	33.5	39.6	70.5	84.9	89.5	111.4	115.4	163.9	212.5
Other Products	185.8	187.0	193.9	201.9	211.6	220.2	268.6	311.2	359.6
Total All Products	**1594.5**	**1657.8**	**1760.1**	**1825.9**	**1871.5**	**1922.1**	**2098.7**	**2230.7**	**2431.2**
Export Formula Case									
Total All Products		**1684.5**	**1816.7**	**1921.3**	**2012.7**	**2112.0**	**2526.3**	**2810.6**	**3080.7**

*Preliminary Actual

EAST OF THE OTTAWA VALLEY
Mb/d

	1975*	1976	1977	1978	1979	1980	1985	1990	1995
NEB Forecast									
Motor Gasoline	217.1	220.3	227.7	231.7	234.7	236.3	230.2	212.7	210.8
Light Fuel Oil, Kerosene and Stove Oil	187.8	189.6	190.4	191.2	192.1	193.5	202.6	215.8	230.3
Diesel Fuel Oil	63.0	67.7	71.5	76.2	78.6	81.1	94.3	110.6	128.1
Heavy Fuel Oil	186.9	193.8	227.5	233.8	239.9	245.9	296.0	300.1	335.8
Petrochemical Feedstock	14.4	18.4	20.7	24.2	24.5	24.7	25.8	26.9	28.0
Other Products	63.7	68.9	72.8	77.0	80.9	84.2	104.1	120.8	140.3
Total All Products	**732.9**	**758.7**	**810.6**	**834.1**	**850.7**	**865.7**	**953.0**	**986.9**	**1073.3**
Export Formula Case									
Total All Products		**776.6**	**843.2**	**885.2**	**923.3**	**961.1**	**1149.0**	**1238.8**	**1346.8**

*Preliminary Actual

WEST OF THE OTTAWA VALLEY

Mb/d

	1975*	1976	1977	1978	1979	1980	1985	1990	1995
NEB Forecast									
Motor Gasoline	378.2	386.3	400.8	410.5	419.8	427.9	447.2	427.6	426.7
Light Fuel Oil, Kerosene and Stove Oil	133.6	138.1	138.5	138.1	137.4	135.6	131.7	130.3	129.9
Diesel Fuel Oil	125.0	132.2	138.1	143.3	148.4	153.5	184.1	216.7	246.5
Heavy Fuel Oil	83.6	103.2	101.2	114.3	119.5	116.7	128.6	141.8	151.0
Petrochemical Feedstock	19.1	21.2	49.8	60.7	65.0	86.7	89.6	137.0	184.5
Other Products	122.1	118.1	121.1	124.9	130.7	136.0	164.5	190.4	219.3
Total All Products	**861.6**	**899.1**	**949.5**	**991.8**	**1020.8**	**1056.4**	**1145.7**	**1243.8**	**1357.9**
Export Formula Case									
Total All Products		**907.9**	**973.5**	**1036.1**	**1089.4**	**1150.9**	**1377.3**	**1571.8**	**1733.9**

*Preliminary Actual

ATLANTIC

Mb/d

	1975*	1976	1977	1978	1979	1980	1985	1990	1995
NEB Forecast									
Motor Gasoline	50.9	52.3	54.2	55.4	56.2	56.6	54.6	49.9	49.2
Light Fuel Oil, Kerosene and Stove Oil	53.7	52.8	53.9	55.4	57.2	58.6	64.0	71.1	79.3
Diesel Fuel Oil	23.3	24.7	25.5	26.2	26.9	27.5	29.8	33.9	39.8
Heavy Fuel Oil	72.8	78.9	105.6	106.3	107.2	108.1	139.3	121.1	131.0
Petrochemical Feedstock	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.8	0.9
Other Products	14.2	15.9	16.8	18.0	18.9	19.7	24.5	28.5	33.2
Total All Products	**215.3**	**225.0**	**256.5**	**261.8**	**267.0**	**271.1**	**312.9**	**305.3**	**333.4**
Export Formula Case									
Total All Products		**229.4**	**265.0**	**274.9**	**285.7**	**296.1**	**363.0**	**368.7**	**401.6**

*Preliminary Actual

QUEBEC
Mb/d

	1975*	1976	1977	1978	1979	1980	1985	1990	1995
NEB Forecast									
Motor Gasoline	144.9	146.4	151.3	153.7	155.4	156.3	151.6	140.0	138.8
Light Fuel Oil, Kerosene and Stove Oil	121.6	123.9	123.6	122.9	122.1	122.2	126.4	132.8	139.5
Diesel Fuel Oil	34.8	38.0	40.8	44.5	46.0	47.6	57.2	67.9	78.3
Heavy Fuel Oil	106.4	107.7	114.1	119.6	124.8	129.9	148.3	170.1	195.4
Petrochemical Feedstock	14.0	18.0	20.2	23.7	23.9	24.1	25.1	26.1	27.1
Other Products	44.5	48.2	51.1	54.0	56.8	59.1	72.9	84.6	98.1
Total All Products	**466.2**	**482.2**	**501.1**	**518.4**	**529.0**	**539.2**	**581.5**	**621.5**	**677.2**
Export Formula Case									
Total All Products		**495.4**	**523.7**	**553.7**	**578.7**	**603.9**	**713.5**	**791.0**	**861.7**

*Preliminary Actual

ONTARIO
Mb/d

	1975*	1976	1977	1978	1979	1980	1985	1990	1995
NEB Forecast									
Motor Gasoline	212.8	215.8	222.1	226.4	230.6	233.8	240.4	228.1	228.3
Light Fuel Oil, Kerosene and Stove Oil	101.9	107.3	107.6	107.3	106.9	105.6	101.7	99.4	96.0
Diesel Fuel Oil	43.8	45.0	47.4	49.6	51.9	54.2	67.1	80.9	92.0
Heavy Fuel Oil	60.6	75.6	73.6	86.6	91.8	89.0	98.0	105.3	107.1
Petrochemical Feedstock	18.5	20.5	49.0	59.8	64.0	65.7	68.1	115.0	116.0
Other Products	59.2	53.5	54.4	55.2	57.7	60.2	74.1	86.0	99.5
Total All Products	**496.8**	**517.7**	**554.1**	**584.9**	**602.9**	**608.5**	**649.4**	**714.7**	**738.9**
Export Formula Case									
Total All Products		**522.0**	**567.4**	**610.2**	**642.5**	**663.3**	**781.9**	**897.2**	**939.7**

*Preliminary Actual

OTTAWA VALLEY

Mb/d

	1975*	1976	1977	1978	1979	1980	1985	1990	1995
NEB Forecast									
Motor Gasoline	21.3	21.6	22.2	22.6	23.1	23.4	24.0	22.8	22.8
Light Fuel Oil, Kerosene and Stove Oil	12.5	12.9	12.9	12.9	12.8	12.7	12.2	11.9	11.5
Diesel Fuel Oil	4.9	5.0	5.2	5.5	5.7	6.0	7.3	8.8	10.0
Heavy Fuel Oil	7.7	7.2	7.8	7.9	7.9	7.9	8.4	8.9	9.4
Petrochemical Feedstock	—	—	—	—	—	—	—	—	—
Other Products	5.0	4.8	4.9	5.0	5.2	5.4	6.7	7.7	9.0
Total All Products	**51.4**	**51.5**	**53.0**	**53.9**	**54.7**	**55.4**	**58.6**	**60.1**	**62.7**
Export Formula Case									
Total All Products		**51.8**	**54.5**	**56.6**	**58.9**	**61.1**	**72.5**	**79.1**	**83.5**

*Preliminary Actual

MANITOBA

Mb/d

	1975*	1976	1977	1978	1979	1980	1985	1990	1995
NEB Forecast									
Motor Gasoline	25.4	25.9	27.5	28.4	29.3	30.0	31.9	30.8	30.6
Light Fuel Oil, Kerosene and Stove Oil	6.5	7.4	7.3	7.2	7.0	6.9	6.7	6.6	6.5
Diesel Fuel Oil	11.4	12.5	12.9	13.2	13.5	13.8	15.8	18.0	20.6
Heavy Fuel Oil	3.7	2.5	2.3	2.1	1.9	1.7	1.6	1.6	1.4
Petrochemical Feedstock	—	—	—	—	—	—	—	—	—
Other Products	7.2	7.3	7.7	8.0	8.6	9.0	11.2	13.2	15.3
Total All Products	**54.2**	**55.6**	**57.7**	**58.9**	**60.3**	**61.4**	**67.2**	**70.2**	**74.4**
Export Formula Case									
Total All Products		**57.7**	**60.5**	**63.1**	**65.9**	**68.2**	**82.4**	**92.0**	**100.2**

*Preliminary Actual

SASKATCHEWAN
Mb/d

	1975*	1976	1977	1978	1979	1980	1985	1990	1995
NEB Forecast									
Motor Gasoline	34.9	35.0	36.0	36.0	36.0	36.5	37.6	35.9	35.2
Light Fuel Oil, Kerosene and Stove Oil	8.0	7.3	7.3	7.3	7.2	7.1	7.0	7.2	7.5
Diesel Fuel Oil	15.0	14.7	15.0	15.3	15.5	15.7	17.6	19.9	22.2
Heavy Fuel Oil	0.6	0.5	0.6	0.5	0.5	0.5	0.6	0.6	0.9
Petrochemical Feedstock	–	–	–	–	–	–	–		-
Other Products	6.4	6.3	6.5	6.7	7.0	7.2	8.6	10.2	11.8
Total All Products	**64.9**	**63.8**	**65.4**	**65.8**	**66.2**	**67.0**	**71.4**	**73.8**	**77.6**
Export Formula Case									
Total All Products		**64.0**	**66.5**	**68.1**	**70.0**	**72.8**	**88.7**	**98.2**	**106.0**

*Preliminary Actual

ALBERTA
Mb/d

	1975*	1976	1977	1978	1979	1980	1985	1990	1995
NEB Forecast									
Motor Gasoline	62.8	66.0	68.9	71.3	73.7	75.8	83.2	81.8	82.8
Light Fuel Oil, Kerosene and Stove Oil	4.2	4.3	4.5	4.5	4.5	4.5	4.6	4.7	4.8
Diesel Fuel Oil	27.9	27.5	28.6	29.6	30.5	31.6	37.0	42.0	47.1
Heavy Fuel Oil	3.2	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.7
Petrochemical Feedstock	0.1	0.1	0.1	0.1	0.1	20.1	20.1	20.1	66.1
Other Products	32.8	33.0	33.1	34.4	35.7	36.9	42.8	48.8	55.4
Total All Products	**131.0**	**132.3**	**136.6**	**141.4**	**146.0**	**170.4**	**189.3**	**199.0**	**257.9**
Export Formula Case									
Total All Products		**132.7**	**140.0**	**147.6**	**155.8**	**183.9**	**223.5**	**250.4**	**319.8**

*Preliminary Actual

BRITISH COLUMBIA
Mb/d

	1975*	1976	1977	1978	1979	1980	1985	1990	1995
NEB Forecast									
Motor Gasoline	61.9	63.4	66.7	69.0	71.2	73.0	75.8	71.6	70.4
Light Fuel Oil, Kerosene and Stove Oil	22.1	20.9	20.8	20.8	20.6	20.2	19.9	20.1	21.8
Diesel Fuel Oil	27.7	31.5	32.8	34.0	35.2	36.2	42.8	50.5	57.6
Heavy Fuel Oil	22.7	29.6	30.1	30.3	30.3	30.4	32.9	38.4	45.3
Petrochemical Feedstock	0.5	0.6	0.7	0.8	0.9	0.9	1.4	1.9	2.4
Other Products	19.5	20.5	21.9	23.0	24.2	25.3	31.0	35.9	41.7
Total All Products	**154.4**	**166.5**	**173.0**	**177.9**	**182.4**	**186.0**	**203.8**	**218.4**	**239.2**
Export Formula Case									
Total All Products		**168.4**	**177.6**	**186.3**	**195.5**	**204.0**	**247.4**	**281.4**	**314.7**

*Preliminary Actual

YUKON & N.W.T.
Mb/d

	1975*	1976	1977	1978	1979	1980	1985	1990	1995
NEB Forecast									
Motor Gasoline	1.7	1.8	1.8	2.0	2.1	2.2	2.3	2.2	2.2
Light Fuel Oil, Kerosene and Stove Oil	3.4	3.8	3.9	3.9	4.0	4.0	4.0	4.2	4.8
Diesel Fuel Oil	4.1	6.0	6.6	7.1	7.5	8.0	11.1	14.2	17.0
Heavy Fuel Oil	0.5	0.8	1.0	1.2	1.4	1.5	2.3	3.2	4.0
Petrochemical Feedstock	—	—	—	—	—	—	—	—	—
Other Products	2.0	2.3	2.4	2.6	2.7	2.8	3.5	4.0	4.6
Total All Products	**11.7**	**14.7**	**15.7**	**16.8**	**17.7**	**18.5**	**23.2**	**27.8**	**32.6**
Export Formula Case									
Total All Products		**14.9**	**16.0**	**17.4**	**18.6**	**19.8**	**25.9**	**31.7**	**37.0**

*Preliminary Actual

Discussion of NEB Demand Forecasting Methodology

Methodology

In the following, a brief discussion is provided of the methodology underlying the total energy and oil demand forecasts presented elsewhere in the report. Further details are available on request from the Board staff.

The demand for refined petroleum products is forecast in a total energy demand framework in which the demand for other energy types is explicitly forecast. Total energy demand (adjusted to take account of the relative burning efficiencies of the various fuels) is forecast in each end-use sector and region using econometric relationships, with projected regional values of economic activity, demographic and price variables. The application of assumed regional market shares yields forecast energy requirements for particular fuels in each end-use sector and region. The demands are forecast in terms of output Btu's. Input energy requirements are determined by dividing by the assumed burning efficiencies for each fuel and sector. Motor gasoline demand is forecast using a somewhat different method which is discussed in some detail below.

The Forecasting Equations — Residential, Commercial and Industrial Sector

For the residential, commercial and industrial sectors, the equations are estimated by pooling time series data (1961-1971) and cross section data (across the five major regions — Atlantic, Quebec, Ontario, Prairies and British Columbia). The data on energy consumption was from the Statistics Canada publication *Detailed Energy Supply and Demand in Canada.*

In the residential sector, total (output) energy demand per household in each region is assumed to be a function of the weather, real personal disposable income per household, the price of energy relative to the consumer price index and the proportion of the housing stock consisting of single dwellings.

In the commercial sector, regional output energy requirements are assumed to depend on the value of retail trade in real terms, the price of energy relative to the consumer price index, the proportion of employment in the commercial sector, and the proportion of the housing stock consisting of multiple dwellings.

Energy demand in the industrial sector is related to the level of industrial output, capital and labour employed in the industrial sector and the price of energy in the industrial sector relative to the price of industrial output.

The basic equations for the residential, commercial and industrial sectors were originally developed at the Department of Energy, Mines and Resources. Several modifications have been made to the estimated equations described above and to the forecasts resulting from these equations. The modifications to the equations included reducing the estimated coefficient for the industrial price variable, revising a lag structure which spreads the price effect over a number of years, and removing the time trend for the Quebec commercial sector. Further, after the modifications were made, an analysis was carried out regarding the differences between forecast and actual values in the recent historical period, and, when deemed appropriate, adjustments were made to the forecasts to put them on track. These modifications and adjustments were made on a judgemental basis.

The approach used in developing the market shares for each fuel in these three sectors was largely judgemental, taking into account appropriate historical trends (from 1960 onwards) and assumptions as to the quantitative impacts of future relative prices. Regarding heavy fuel oil, information obtained through surveys conducted by the Board regarding short term future consumption plans of large industrial consumers was utilized.

Petrochemicals

The forecast of oil requirements for the production of petrochemicals was developed by forecasting of the production of primary petrochemicals (e.g. ethylene) in Canada, and then translating these demands into forecasts of oil and gas requirements for these levels of production. For the earlier years of the forecast period (generally through 1980), the forecasts of petrochemical production were based on an evaluation of information regarding company plans and proposals for petrochemical production. For the later years, the production forecasts were based on forecasts of Canadian demand for primary petrochemicals. In the case of ethylene, for example, it was assumed that Canadian production would come on stream to satisfy forecast Canadian demand (no imports) throughout the forecast period. Further, exports of 350 million pounds of ethylene per year were assumed between

1978 and 1988. The geographical distribution of forecast primary petrochemical production (plant location) and the type of feedstock to be used were determined on a judgemental basis, utilizing information from various sources. Historical data on oil used as a feedstock for petrochemical production (through the first six months of 1976) was obtained from the Statistics Canada publication *Refined Petroleum Products*, catalogue 45-004, monthly.

Road Transportation Sector

The Motor Gasoline Model

This section describes the modelling steps from estimates of new car sales to forecasts of auto gasoline consumption.

The first step is to estimate total sales of passenger automobiles by using a regression equation which states that total auto sales per capita (including only persons in the driver age) depend positively upon per capita personal disposable income and negatively upon the unemployment rate and the real gasoline price index, that is, the gasoline price index deflated by the consumer price index. The equation uses pooled cross-section and time series data for the period 1966-1973 for nine provinces (72 observations) which exclude PEI and the Northwest Territories. Estimates of total auto sales obtained from the equation serve as a constraint on the total of sales of subcompact, compact, intermediate and full-sized models derived in the second step.

In the second step, sales of subcompact, compact, and full-sized models are estimated using equations for these model types. Sales of intermediate models are obtained from the constraint that the sum of sales on the four model types must equal total auto sales obtained in the first step.

The equation used in estimating sales of subcompact models relates sales of subcompacts to per capita real disposable income and the relative price of subcompacts, that is, the price of subcompacts relative to the average of prices of compact, intermediate and full-sized models. The equation for compact models postulates that sales of compacts depend positively upon the percentage rate of change in the real index of gasoline price, and negatively upon the unemployment rate and the relative price of compacts, that is, the price of compacts relative to the average of prices of subcompact, intermediate and full-sized models. The equation for full-sized models in total auto sales depends negatively upon the unemployment rate and the real price of full-sized models, that is, the price of full-sized models deflated by the consumer price index.

The third step involves adding the sales of the four model types to their respective stocks outstanding at the beginning of the year to obtain estimates of subcompact, compact, intermediate and standard cars on the road in a given year. Estimates of stocks of cars outstanding at the beginning of the year are obtained by applying retirement ratios for each car type in each province to the respective aggregate of the car type on the road during last year.

Retirement ratios for each model type in each province are estimated using equations which relate percentage of models of a given year on the road to the age of the model. There are 36 retirement equations for four model types in nine provinces.

Estimates of numbers of subcompact, compact, intermediate, and full-sized models on the road are then multiplied by estimates of mileage travelled by each type and age to obtain estimates of mileage travelled by each type.

Estimates of mileage travelled by each model type are obtained using equations which relate mileage travelled by a model type to its age. There are four auto mileage equations, one for each model type.

Mileage travelled by each model type is then divided into urban and nonurban mileage by applying exogenously determined proportions of urban and nonurban (mainly highway) mileage. This step thus gives estimates of urban and nonurban mileage travelled by each of the four auto types.

Finally, estimates of urban and nonurban mileage travelled by each car type are divided by exogenous estimates of urban and nonurban fuel economies to obtain estimates of gasoline consumption for urban and nonurban travel by the four types. Total gasoline consumption by automobiles for any given year, can then be obtained by adding urban and nonurban consumption by the four car types. The non-automobile component of motor gasoline sales was estimated as a percentage of automobile gasoline sales. Adjustments to the model outputs were made to put the sales on track for 1975.

Diesel Fuel — Road Transportation

The forecast of road diesel fuel oil is derived by applying judgemental estimates to the results of an equation which relates consumption to real domestic product and a time trend. These forecasts were modified in the light of recent diesel consumption data, expected fuel economies in new trucks and anticipated effects of higher prices.

Rail, Air and Marine Transportation Sector

For each of the rail, air and marine transportation sectors, an equation was developed on the basis of historical demand using time series data for total Canada. For the air and marine sectors, the estimation period was 1958-1973 and for the rail sector, 1960-1973.

Rail and marine transportation total energy demands are related to real domestic product in mining, manufacturing and agriculture which are the sectors providing the bulk of goods transported by rail and by ship. A national forecast of total energy requirements is obtained and then the market shares for each fuel are applied. The demand for each fuel in each of seven regions is obtained by applying regional shares which have been determined through analysis of historical trends or Board contacts with shippers.

In the air transportation sector, an equation relates real gross national product and the index of real air fares to consumption per capita of the total of aviation gasoline and aviation turbo fuel. The demand for aviation gasoline is then forecast for various subsectors — Canadian commercial airlines, domestic governments, foreign airlines and governments and general aviation. This forecast of consumption of aviation gasoline obtained through analysis of historical trends and market intelligence is then subtracted from the national forecast of total fuel use to obtain the forecast of requirements for turbo fuel. Regional spreading ratios are then applied to each of the fuel forecasts to result in a forecast in each region. The aviation fuel demands are included in the "other products" category in this report.

Other Products

The demand for lubes and greases, and asphalt are obtained from equations relating these demands to the previous year's demand and the current level of real domestic product.

COMPARISON OF NEB AND EMR DEMAND FORECASTS

The tables below compare selected economic, demographic and energy demands for three energy projections. The first column represents one of the scenarios published by the Department of Energy, Mines and Resources in *An Energy Strategy for Canada.* This is referred to as the EMR 1976 projection. The EMR projections for individual petroleum products shown below are derived from unpublished documentation provided to the Board by EMR. The forecast published by the Board in September 1975, *Canadian Oil Supply and Requirements* is referred to as the NEB 1975 forecast while the current Scenario I forecast is referred to as NEB 1977.

The EMR scenario selected is the one in which the assumptions regarding economic growth and the international oil prices most closely resemble the assumptions of the NEB Scenario I.

	EMR 1976	NEB 1975	NEB 1977
Real Gross National Product			
% Average Annual Growth			
1976-1980	5.4%	5.0%	5.4%
1980-1990	3.6%	4.5%	3.6%
Population			
% Average Annual Growth			
1961-1970	1.8%	1.8%	1.8%
1976-1980	1.3%	1.3%	1.3%
1980-1990	1.2%	1.2%	1.2%
Total Primary Energy Demand			
Trillions of Btu's			
1980	9805	11,128	9662
1985	11,469	13,818	11,042
1990	13,472	17,035	12,460
Total Primary Energy Demand			
% Average Annual Growth			
1975-1980	4.5%	5.7%	3.9%
1980-1985	3.2%	4.4%	2.7%
1985-1990	3.3%	4.4%	2.4%

	EMR 1976	NEB 1975	NEB 1977
Total Petroleum Product Demand Mb/d			
1980		1988	1922
1985		2289	2099
1990		2649	2231
Motor Gasoline Demand Mb/d			
1980	686*	637	664
1985	811*	716	677
1990	938*	821	640
Light Fuel Oil, Kerosene Demand Mb/d			
1980	366	335	329
1985	327	357	334
1990	290	381	346
Diesel Fuel Oil Demand Mb/d			
1980	175	243	235
1985	196	300	278
1990	219	369	327
Heavy Fuel Oil Demand Mb/d			
1980	356	432**	363
1985	354	474**	425
1990	351	525**	442
Conservation of Total Petroleum Products for purposes of Oil Export Formula			
1980		6%	9%
1985		9%	17%
1990		11%	21%
Basic Price Assumptions;			
Domestic Price Approaches International Price	1978	1980	1980
Natural Gas Reaches Btu Parity with Crude	1978	1978	1980

* This EMR scenario does not include the effects of the Federal Government fuel economy targets. The ***Strategy Paper*** indicated that with the inclusion of these mileage standards, gasoline demand would be substantially reduced.

** Adjusted upwards by 30 Mb/d shown in the 1976 NEB report as petrochemical feedstock.

1975 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT
Comparison of Forecasts
Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula Case
Total Market Product Sales	731	716	735	748	733	–
Deduct Product Imports	28	31	28	29	28	–
Add Product Exports	54	51	64	56	54	–
Net Product Transfers Out/(In)	32	46	30	24	30	–
Losses, Industry Use and Other Adjustments	34	58	23	60	33	–
Deduct Gas Plant Butanes Supplied to Refineries	–	–	–	–	–	–
Deduct Foreign Feedstock Refined	816	830	818	851	815	–
Indigenous Crude Oil and Equivalent Requirements	7	10	6	8	7	–
West of the Ottawa Valley Line						
Total Market Product Sales	853	865	848	872	862	–
Deduct Product Imports	12	11	9	12	12	–
Add Product Exports	41	35	40	38	32	–
Net Product Transfers Out/(In)	(32)	(46)	(30)	(24)	(30)	–
Losses, Industry Use and Other Adjustments	30	50	41	76	34	–
Deduct Gas Plant Butanes Supplied to Refineries	10	14	12	11	14	–
Deduct Foreign Feedstock Refined	1	–	–	–	1	–
Indigenous Crude Oil and Equivalent Requirements	869	879	878	939	871	–
Canada						
Total Market Product Sales	1584	1581	1583	1620	1595	–
Deduct Product Imports	40	42	37	(41)	40	–
Add Product Exports	95	86	104	94	86	–
Losses, Industry Use and Other Adjustments	64	108	64	136	67	–
Deduct Gas Plant Butanes Supplied to Refineries	(10)	(14)	(12)	(11)	14	–
Deduct Foreign Feedstock Refined	(817)	(830)	(818)	(851)	816	–
Indigenous Crude Oil and Equivalent Requirements	876	889	884	947	878	–

1976 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT
Comparison of Forecasts
Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula Case
Total Market Product Sales	770	760	793	773	759	777
Deduct Product Imports	9	46	11	48	23	23
Add Product Exports	42	28	14	73	34	34
Net Product Transfers Out/(In)	31	49	15	37	18	18
Losses, Industry Use and Other Adjustments	54	64	52	58	18	18
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	—	—	—
Deduct Foreign Feedstock Refined	778	765	782	773	716	734
Indigenous Crude Oil and Equivalent Requirements	110	90	81	120	90*	90
West of the Ottawa Valley Line						
Total Market Product Sales	877	905	901	912	899	908
Deduct Product Imports	7	9	28	15	14	14
Add Product Exports	31	35	18	30	30	30
Net Product Transfers Out/(In)	(31)	(49)	(15)	(37)	(18)	(18)
Losses, Industry Use and Other Adjustments	46	57	56	85	7	7
Deduct Gas Plant Butanes Supplied to Refineries	11	22	12	11	19	19
Deduct Foreign Feedstock Refined	—	—	—	—	—	—
Indigenous Crude Oil and Equivalent Requirements	905	917	920	964	885	894
Canada						
Total Market Product Sales	1647	1665	1694	1685	1658	1685
Deduct Product Imports	16	55	39	63	37	37
Add Product Exports	73	63	32	103	64	64
Losses, Industry Use and Other Adjustments	100	121	108	143	25	25
Deduct Gas Plant Butanes Supplied to Refineries	11	22	12	11	19	19
Deduct Foreign Feedstock Refined	778	765	782	773	716	734
Indigenous Crude Oil and Equivalent Requirements	1015	1007	1001	1084	975	984

*includes line fill

1977 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT
Comparison of Forecasts
Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula Case
Total Market Product Sales	791	805	820	801	810	843
Deduct Product Imports	--	69	15	48	67	67
Add Product Exports	42	28	27	86	7	7
Net Product Transfers Out/(In)	33	27	15	29	18	18
Losses, Industry Use and Other Adjustments	57	66	55	60	44	46
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	—	—	—
Deduct Foreign Feedstock Refined	673	607	652	678	562	597
Indigenous Crude Oil and Equivalent Requirements	250	250	250	250	250	250
West of the Ottawa Valley Line						
Total Market Product Sales	939	938	959	948	950	974
Deduct Product Imports	3	6	31	14	18	18
Add Product Exports	50	35	23	39	49	49
Net Product Transfers Out/(In)	(33)	(27)	(15)	(29)	(18)	(18)
Losses, Industry Use and Other Adjustments	55	63	61	84	41	42
Deduct Gas Plant Butanes Supplied to Refineries	11	23	12	11	23	23
Deduct Foreign Feedstock Refined	—	—	—	—	—	—
Indigenous Crude Oil and Equivalent Requirements	997	980	985	1017	981	1006
Canada						
Total Market Product Sales	1730	1743	1779	1749	1760	1817
Deduct Product Imports	3	75	46	62	85	85
Add Product Exports	92	63	50	125	56	56
Losses, Industry Use and Other Adjustments	112	129	116	144	85	88
Deduct Gas Plant Butanes Supplied to Refineries	11	23	12	11	23	23
Deduct Foreign Feedstock Refined	673	607	652	678	562	597
Indigenous Crude Oil and Equivalent Requirements	1247	1230	1235	1267	1231	1256

1978 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT
Comparison of Forecasts
Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula Case
Total Market Product Sales	810	834	845	834	834	885
Deduct Product Imports	–	96	13	50	58	58
Add Product Exports	42	35	39	94	10	10
Net Product Transfers Out/(In)	33	17	15	26	2	2
Losses, Industry Use and Other Adjustments	57	67	56	62	44	47
Deduct Gas Plant Butanes Supplied to Refineries	–	–	–	–	–	–
Deduct Foreign Feedstock Refined	692	607	692	716	582	636
Indigenous Crude Oil and Equivalent Requirements	250	250	250	250	250	250
West of the Ottawa Valley Line						
Total Market Product Sales	975	984	1015	1001	992	1036
Deduct Product Imports	4	5	28	13	22	22
Add Product Exports	60	28	27	68	93	93
Net Product Transfers Out/(In)	(33)	(17)	(15)	(26)	(2)	(2)
Losses, Industry Use and Other Adjustments	58	65	63	83	54	57
Deduct Gas Plant Butanes Supplied to Refineries	11	24	12	11	24	24
Deduct Foreign Feedstock Refined	–	–	–	–	–	–
Indigenous Crude Oil and Equivalent Requirements	1045	1031	1050	1102	1091	1138
Canada						
Total Market Product Sales	1785	1818	1860	1835	1826	1920
Deduct Product Imports	4	101	41	63	80	80
Add Product Exports	102	63	66	162	103	103
Losses, Industry Use and Other Adjustments	115	132	119	145	98	104
Deduct Gas Plant Butanes Supplied to Refineries	11	24	12	11	24	24
Deduct Foreign Feedstock Refined	692	607	692	716	582	636
Indigenous Crude Oil and Equivalent Requirements	1295	1281	1300	1352	1341	1388

1979 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT
Comparison of Forecasts
Mb/d

	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula Case
East of the Ottawa Valley Line						
Total Market Product Sales	829	862	866	864	851	923
Deduct Product Imports	–	103	9	52	70	70
Add Product Exports	42	28	51	103	13	13
Net Product Transfers Out/(In)	33	11	15	26	(10)	(10)
Losses, Industry Use and Other Adjustments	58	69	58	63	43	47
Deduct Gas Plant Butanes Supplied to Refineries	–	–	–	–	–	–
Deduct Foreign Feedstock Refined	712	617	731	754	577	653
Indigenous Crude Oil and Equivalent Requirements	250	250	250	250	250	250
West of the Ottawa Valley Line						
Total Market Product Sales	998	1022	1045	1042	1021	1089
Deduct Product Imports	5	5	29	13	23	23
Add Product Exports	60	35	33	76	87	87
Net Product Transfers Out/(In)	(33)	(11)	(15)	(26)	10	10
Losses, Industry Use and Other Adjustments	59	67	65	87	58	61
Deduct Gas Plant Butanes Supplied to Refineries	11	25	12	11	25	25
Deduct Foreign Feedstock Refined	–	–	–	–	–	–
Indigenous Crude Oil and Equivalent Requirements	1068	1083	1087	1155	1128	1199
Canada						
Total Market Product Sales	1827	1884	1911	1906	1872	2012
Deduct Product Imports	5	108	38	65	93	93
Add Product Exports	102	63	84	179	100	100
Losses, Industry Use and Other Adjustments	117	136	123	150	101	108
Deduct Gas Plant Butanes Supplied to Refineries	11	25	12	11	25	25
Deduct Foreign Feedstock Refined	712	617	731	754	577	653
Indigenous Crude Oil and Equivalent Requirements	1318	1333	1337	1405	1378	1449

1980 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT
Comparison of Forecasts
Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula Case
Total Market Product Sales	853	889	889	892	866	961
Deduct Product Imports	–	109	–	53	64	64
Add Product Exports	42	28	60	110	17	17
Net Product Transfers Out/(In)	33	9	–	26	(19)	(19)
Losses, Industry Use and Other Adjustments	61	71	61	67	44	49
Deduct Gas Plant Butanes Supplied to Refineries	–	–	–	–	–	–
Deduct Foreign Feedstock Refined	739	638	760	792	594	694
Indigenous Crude Oil and Equivalent Requirements	250	250	250	250	250	250
West of the Ottawa Valley Line						
Total Market Product Sales	1079	1054	1105	1072	1056	1151
Deduct Product Imports	8	5	48	14	25	25
Add Product Exports	60	35	48	82	91	91
Net Product Transfers Out/(In)	(33)	(9)	–	(26)	19	19
Losses, Industry Use and Other Adjustments	61	73	71	91	60	65
Deduct Gas Plant Butanes Supplied to Refineries	12	28	12	11	28	28
Deduct Foreign Feedstock Refined	–	–	–	–	–	–
Indigenous Crude Oil and Equivalent Requirements	1147	1120	1164	1194	1173	1273
Canada						
Total Market Product Sales	1932	1943	1994	1964	1922	2112
Deduct Product Imports	8	114	48	67	89	89
Add Product Exports	102	63	108	192	108	108
Losses, Industry Use and Other Adjustments	122	144	132	158	104	114
Deduct Gas Plant Butanes Supplied to Refineries	12	28	12	11	28	28
Deduct Foreign Feedstock Refined	739	638	760	792	594	694
Indigenous Crude Oil and Equivalent Requirements	1397	1370	1414	1444	1423	1523

1985 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT
Comparison of Forecasts
Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula Case
Total Market Product Sales	923	1011	904	1042	953	1149
Deduct Product Imports	—	103	—	60	60	60
Add Product Exports	42	28	133	116	15	15
Net Product Transfers Out/(In)	33	(16)	—	17	—	—
Losses, Industry Use and Other Adjustments	64	76	64	76	48	58
Deduct Gas Plant Butanes Supplied to Refineries	—	—	—	—	—	—
Deduct Foreign Feedstock Refined	863	996	1101	1191	706	912
Indigenous Crude Oil and Equivalent Requirements	199	—	—	—	250	250
West of the Ottawa Valley Line						
Total Market Product Sales	1151	1225	1202	1214	1146	1377
Deduct Product Imports	15	—	60	16	—	—
Add Product Exports	60	7	46	61	60	60
Net Product Transfers Out/(In)	(33)	16	—	(17)	—	—
Losses, Industry Use and Other Adjustments	69	88	78	101	62	74
Deduct Gas Plant Butanes Supplied to Refineries	11	43	12	11	28	28
Deduct Foreign Feedstock Refined	—	57	—	88	—	—
Indigenous Crude Oil and Equivalent Requirements	1221	1236	1254	1244	1240	1483
Canada						
Total Market Product Sales	2074	2236	2106	2256	2099	2526
Deduct Product Imports	15	103	60	76	60	60
Add Product Exports	102	35	179	177	75	75
Losses, Industry Use and Other Adjustments	133	164	142	177	110	132
Deduct Gas Plant Butanes Supplied to Refineries	11	43	12	11	28	28
Deduct Foreign Feedstock Refined	863	1053	1101	1279	706	912
Indigenous Crude Oil and Equivalent Requirements	1420	1236	1254	1244	1490	1733

1990 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT
Comparison of Forecasts
Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula Case
Total Market Product Sales	988	1121	960	1201	987	1239
Deduct Product Imports	–	90	2	67	60	60
Add Product Exports	42	–	122	123	15	15
Net Product Transfers Out/(In)	(33)	(1)	–	12	–	–
Losses, Industry Use and Other Adjustments	69	80	69	86	50	63
Deduct Gas Plant Butanes Supplied to Refineries	–	–	–	–	–	–
Deduct Foreign Feedstock Refined	882	1020	1149	1355	742	1007
Indigenous Crude Oil and Equivalent Requirements	250	90	–	–	250	250
West of the Ottawa Valley Line						
Total Market Product Sales	1217	1385	1269	1367	1244	1572
Deduct Product Imports	17	–	63	18	–	–
Add Product Exports	60	10	102	90	5	5
Net Product Transfers Out/(In)	(33)	1	–	(12)	–	–
Losses, Industry Use and Other Adjustments	71	100	85	112	64	81
Deduct Gas Plant Butanes Supplied to Refineries	11	43	12	11	28	28
Deduct Foreign Feedstock Refined	–	176	300	163	–	–
Indigenous Crude Oil and Equivalent Requirements	1287	1277	1081	1365	1285	1630
Canada						
Total Market Product Sales	2205	2506	2229	2568	2231	2811
Deduct Product Imports	17	90	65	85	60	60
Add Product Exports	102	10	224	213	20	20
Losses, Industry Use and Other Adjustments	140	180	154	198	114	144
Deduct Gas Plant Butanes Supplied to Refineries	11	43	12	11	28	28
Deduct Foreign Feedstock Refined	882	1196	1449	1518	742	1007
Indigenous Crude Oil and Equivalent Requirements	1537	1367	1081	1365	1535	1880

1995 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT
Comparison of Forecasts
Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula Case
Total Market Product Sales	1048	1221	1020	1379	1073	1347
Deduct Product Imports	–	106	5	74	60	60
Add Product Exports	42	–	156	129	15	15
Net Product Transfers Out/(In)	33	7	–	6	–	–
Losses, Industry Use and Other Adjustments	75	84	76	96	51	65
Deduct Gas Plant Butanes Supplied to Refineries	–	–	–	–	–	–
Deduct Foreign Feedstock Refined	948	691	1247	1536	829	1117
Indigenous Crude Oil and Equivalent Requirements	250	515	–	–	250	250
West of the Ottawa Valley Line						
Total Market Product Sales	1290	1523	1417	1527	1358	1734
Deduct Product Imports	20	–	88	19	–	–
Add Product Exports	60	12	110	95	5	5
Net Product Transfers Out/(In)	(33)	(7)	–	(6)	–	–
Losses, Industry Use and Other Adjustments	75	106	92	126	70	90
Deduct Gas Plant Butanes Supplied to Refineries	10	39	12	11	28	28
Deduct Foreign Feedstock Refined	–	261	250	137	–	–
Indigenous Crude Oil and Equivalent Requirements	1362	1334	1269	1575	1405	1801
Canada						
Total Market Product Sales	2338	2744	2437	2906	2431	3081
Deduct Product Imports	20	106	93	93	60	60
Add Product Exports	102	12	266	224	20	20
Losses, Industry Use and Other Adjustments	150	190	168	222	121	155
Deduct Gas Plant Butanes Supplied to Refineries	10	39	12	11	28	28
Deduct Foreign Feedstock Refined	948	952	1497	1673	829	1117
Indigenous Crude Oil and Equivalent Requirements	1612	1849	1269	1575	1655	2051

REQUIREMENTS FOR INDIGENOUS HEAVY CRUDE OIL
Comparison of Forecasts
Mb/d

	AERCB	Ashland	Gulf	Husky	IPAC(1)	Pacific	Pan Cdn.	Shell	NEB(2)
1976	55	46	90	92	71.3	72	75	46	79
1977	67	49	120	95		74	70	50	98
1978	85	52	127	98		77	73	52	108
1979	95	54	114	100		80	75	56	112
1980	103	64	115	103	109.2	83	83	58	115
1985	124	61	87	113	102.9	98	82	62	134
1990	148	78	89	125	116.7	118	94	62	150
1995	180	93	88	136	129.2	140	106	76	169

(1) Figures shown for 1980, 85 and 90 were submitted as 1981, 86, 91.
(2) Details below.

	WOV Requirements for Asphalt — Yielding Crude Oil	Requirements for Midale Crude Oil	Total WOV	Montreal Requirements	Total Canada
1976	52	22	74	5	79
1977	55	18	73	25	98
1978	58	15	73	35	108
1979	62	15	77	35	112
1980	65	15	80	35	115
1985	84	15	99	35	134
1990	100	15	115	35	150
1995	119	15	134	35	169

REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT
NEB Forecast
Mb/d

	NEB FORECAST			NEB EXPORT FORMULA CASE		
	Total	Heavy Crude Oil	Light Crude Oil and Equivalent	Total	Heavy Crude Oil	Light Crude Oil and Equivalent
1976	975	79	896	984	79	905
1977	1231	98	1133	1256	98	1158
1978	1341	108	1233	1388	108	1280
1979	1378	112	1266	1449	112	1337
1980	1423	115	1308	1523	115	1408
1985	1490	134	1356	1733	134	1599
1990	1535	150	1385	1880	150	1730
1995	1655	169	1486	2051	169	1882

NOTE: Included in requirements are the following volumes of crude shipped to refineries east of the Ottawa Valley Line:

1976 – 90 Mb/d shipped by pipeline, including line fill

1977 to 1995 – 250 Mb/d shipped by pipeline

APPENDIX O

NEB NEWS RELEASE OF 23 NOVEMBER, 1976

1977 EXPORTS OF CRUDE OIL AND EQUIVALENT

Ottawa — The National Energy Board announced today that, pending the outcome of the Oil Supply and Requirements Hearing held during October, it has made a decision with respect to exports of crude oil and equivalent hydrocarbons from January 1st, 1977 until further notice. The essential details are as follows:

- light crude oil and heavy crude oil will be licensed separately
- based on the data and the formula contained in the Board's September 1975 Report on Canadian Oil Supply and Requirements, the volume of light crude oil available for licensing will be 180 Mb/d
- the volume of heavy crude oil available for licensing will be the difference between the Board's estimates of Canadian heavy oil producibility and Canadian demand, now anticipated to be some 125 Mb/d for January
- steps will be taken, if necessary, to maintain minimum exports of Lloydminster-type blend crude oil at the current level
- the volumes to be licensed for January will be determined early in December when the January nominations of Canadian refiners have been received

For licensing purposes, the light crude oil category will include condensate and synthetic crude oil. As in the past, the heavy crude oil category will include Lloydminster-type blends, Smiley-Coleville heavy blend, Fosterton, Midale-Weyburn, Bow River, Chauvin, Viking-Kinsella, Wainwright and any other export streams below 25° API.

The levels of export are subject to modification upon publication, early in 1977 of the Board's report of its findings on the October hearing.

BIBLIOGRAPHY OF ENERGY DEMAND STUDIES

Anderson, K.P. (1973), "Residential Energy Use: An Econometric Analysis", Prepared for the National Science Foundation, R 1297-NSF, Rand, October.

Balestra, P. (1967), *The Demand for Natural Gas In the U.S.* (North Holland Publishing Company, Amsterdam).

Baxter, R.E. and Rees, R., "Analysis of the Industrial Demand for Electricity", *Economic Journal,* June 1968, pg. 277-298.

Berndt, E.R. (1976), "Economic Growth and Demand for Energy In Canada: A Survey" (Unpublished).

Berndt, E.R. and Watkins, G.C. (1974), *Projections of Alberta Aggregate Energy Demand, 1974-85,* Joint Submission of Pan Alberta Gas Ltd. and Alberta Gas Trunk Line, Ltd., to proceeding 6147, Alberta Energy Resources Conservation Board, May.

Berndt, E.R. and Watkins, G.C. (1975), "A Residential and Commercial Natural Gas Demand Model for Ontario and British Columbia" in Conference Proceedings, *The Economics of Oil and Gas Self-Sufficiency in Canada,* University of Calgary, October.

Berndt, E.R. and Wood, D.O. (1975), "Technology, Prices and the Derived Demand for Energy", *Review of Economics and Statistics,* August, pg. 259-267.

Coombs, J.A. (1969), "A Cross-Sectional Study of Energy Demand in Canadian Manufacturing Industries, 1964", M.A. Thesis, Department of Economics, Queen's University, September.

Data Resources, Inc. "Energy Model", Unpublished, Lexington, Mass., 1974.

Denny, M.G.S. and Pinto, C., "The Demand for Energy in Canadian Manufacturing, 1949-70", Mimeographed, University of Toronto, 1975.

Erickson, E.W., Spann, R.M., and Ciliano, R. (1973), "Fossil Fuel Energy Demand Analysis". (Report to the Office of Science and Technology, Decision Sciences Corporation), Mimeographed.

Federal Energy Administration (1976), "The Project Independence Evaluation Systems Econometric Demand Model" in *National Energy Outlook,* pg. C-1 to C-39.

Fisher, F.M. and Kaysen, C.A. (1962), *A Study in Econometrics: The Demand for Electricity In the U.S.* (Amsterdam: North Holland Publishing Company).

Foothills Pipe Lines Ltd. (DataMetrics Ltd.) "Forecasts of Residential and Commercial Natural Gas Requirements, Canada, 1973-2002" in Submission by Foothills to NEB Hearings on Requirements for and Supply of Canadian Natural Gas (May 1974), pg. III-14 to III-90.

Fuss, M. and Waverman, L. (1975), *The Demand for Energy in Canada* (Report for the Department of Energy, Mines and Resources).

Gorbet, F.W. (1974), *Energy Demand Model: An Analytical Framework,* December.

Griffin, James M. (1974), "The Effect of Higher Prices on Electricity Consumption", *Bell Journal of Economics and Management Science,* Autumn, pg. 515-539.

Halvorsen, R. (1973), "Demand for Electric Power in the United States". Discussion Paper No. 73-13. Institute for Economic Research, University of Washington, Seattle.

Houthakker, H.S. and Taylor, L.D. (1970), *Consumer Demand in the United States* (Cambridge: Harvard University Press).

Houthakker, H.S., Verleger, P.K., and Sheehan, D.P. (1973), "Dynamic Demand Analysis for Gasoline and Residential Electricity", (Lexington, Mass.; Data Resources, Inc.)

Hudson, E.A. and Jorgensen, D.W. (1974), "U.S. Energy Policy and Economic Growth, 1975-2000", *Bell Journal of Economics and Management Science,* Autumn, pg. 461-514.

Hyndman, R.M. (1975), *Residential Demand for Energy in Canada,* An Unpublished Doctoral Dissertation Submitted to the University of Toronto.

Kennedy, Michael (1974), "An Economic Model of the World Oil Market", *Bell Journal of Economics and Management Science,* Autumn, pg. 540-575.

Lyman, R.A. (1973), "Price Elasticities in the Electric Power Industry", Department of Economics, University of Arizona, October.

McRae, Robert (1976), Demand Sector in John F. Helliwell and others, *An Integrated Model for Energy Policy Analysis,* June 28 (Unpublished).

Ministry of Treasury, Economics and Intergovernmental Affairs (TEIGA), Policy Planning Branch, 1976, *Growth in Ontario's Demand For Electric Energy,* June.

Mount, T.D., Chapman, L.D. and Tyrrell, T.J., (1973), "Electricity Demand in the United States: An Econometric Analysis" Oak Ridge National Laboratory (ORNL-NSF-49), Oak Ridge, Tenn., June.

Taylor, L.D., (1975) "The Demand for Electricity: A Survey", *The Bell Journal of Economics and Management Science,* Spring, pg. 74-110.

Waverman, L. and Fuss, M. (1975), The Demand for Energy in Canada" (Report for the Department of Energy, Mines and Resources)

Waverman, L. (1975), "Estimating the Demand for Energy: Heat Without Light", in Conference Proceedings, *The Economics of Oil and Gas Self-Sufficiency in Canada,* University of Calgary, October.

Wilson, J.W. (1971), "Residential Demand for Electricity", Quarterly Review of Economics and Business, Spring, pg. 7-22.

Canadian Oil
Supply and Requirements

National Energy Board
September 1978

PHOTO CREDIT: PHOTOTHÈQUE
Oil pump in a wheat field,
Saskatchewan

CANADIAN OIL

Supply and Requirements

National Energy Board
September 1978

Cat. No. NE23-11/1978

ISBN 0-662-10129-4

NATIONAL ENERGY BOARD
OTTAWA, ONTARIO
KIA OE5

CANADA

OFFICE NATIONAL DE L'ÉNERGIE
OTTAWA, ONTARIO
KIA OE5

11 September 1978

The Honourable Alastair Gillespie, P.C.,
Minister of Energy, Mines and Resources,
Ottawa, Ontario.

Dear Mr. Gillespie:

In accordance with the provisions of Section 22(2) of the National Energy Board Act, I am pleased to submit the Board's response to your request of 16 January 1978 that the Board investigate and report on a range of possible oil supply situations that might occur over the next 10 to 15 years and the import dependency that might develop for British Columbia consumers, as well as for eastern Canadians.

As you know, the Board held a public inquiry to seek information and views concerning oil supply and demand matters in order to assist it in responding to your request. The Board's report, entitled "Canadian Oil Supply and Requirements, September 1978", which contains a summary of the evidence and the Board's conclusions, is attached.

On the basis of its current projection of oil supply and requirements, the Board concludes that it should not be necessary to increase the capacity of existing oil importing facilities during the forecast period ending in 1995. This is a change from the view the Board expressed in its 1977 oil report that it was likely that refineries west of the Ottawa Valley would need imported oil in the 1980's. The changed outlook reflects a lower anticipated increase in demand as well as an improved supply forecast, particularly in oil sands development.

Having concluded that existing oil importing facilities should be adequate over the forecast period, it is not necessary to comment on the relative merits of the east coast and west coast for new port facilities.

The Board's conclusions have been based upon conditions foreseen at the time of the inquiry. The recent government announcements concerning changes in the pricing mechanism for both oil and gas could have some effect on the Board's oil supply and demand forecasts. However, the Board would not expect this to change the general conclusions contained in the report.

You will note in the report that the Board has reviewed and commented upon other matters, such as determination of export volumes, that were not included in your request but were discussed at the inquiry.

Yours sincerely,

J G Stabback

J.G. Stabback,
Chairman

CONTENTS

LIST OF APPENDICES

List of Appendices Also in Metric Units

LIST OF FIGURES

LIST OF TABLES

COUNSEL AND WITNESSES

A public inquiry into the supply of Canadian oil, the domestic demand for oil and for indigenous feedstocks, the import dependency of Eastern Canada and potential demand for imported oil in British Columbia and other parts of Canada presently served by indigenous oil, and related matters, held pursuant to sections 22(2) and 24 of the National Energy Board Act.

File: 1722-9-3

HEARD AT Calgary, Alberta on 24, 25 and 26 May 1978
Vancouver, British Columbia on 31 May and 1 June 1978
Halifax, Nova Scotia on 9 and 10 June 1978
Ottawa, Ontario on 13, 14, 15, 16, 19, 20, 21 and 22 June 1978

BEFORE

J.G. Stabback,
Chairman,
National Energy Board.

R.F. Brooks,
Associate Vice-Chairman,
National Energy Board.

R.A. Stead,
Member,
National Energy Board.

APPEARANCES:

Calgary	H.L. Hooker	Amoco Canada Petroleum Company Ltd.
	S. Wiltshire	Ashland Oil Canada Limited
	D.H. Blackman A.F. Burchnall	BP Exploration Canada Limited
	R.E. McLennan	Canadian Hidrogas Resources Ltd.
	H. Maciej	Canadian Petroleum Association
	G.F. Paschen	Canadians for Responsible Northern Development

R.R. Mahaffey	Chevron Canada Limited
R.R. Mahaffey	Chevron Standard Limited
R.C. Muir	Dome Petroleum Limited
L.E. Leonoff	Dow Chemical of Canada, Ltd.
F.J. Mink G. Berndtsson	Energy Resources Conservation Board of Alberta
R.J. Gibbs	Foothills Pipe Lines (Yukon) Ltd.
L.D. Horne	Gulf Canada Limited
R. Edwards	Government of British Columbia
T.S. Hoar	Home Oil Company Limited
R. Perrin	Hudson's Bay Oil and Gas Company Limited
G.M. Burden	Independent Petroleum Association of Canada
J.L. Smith	McDaniel Consultants (1965) Ltd.
H.D. Wasden	Mobil Oil Canada, Ltd.
G.C. Thompson	Murphy Oil Company Ltd.
J.J. Marshall	Norcen Energy Resources Limited
J. Kruyer	Oleophilic Sieve Society of Alberta
J.L. Smith	Pacific Petroleums Ltd.
S.A. Thomson	Panarctic Oils Ltd.
D.F. Brown	Petrochemicals Alberta Project
J. Wansleeben	Petrofina Canada Ltd.

	D. Trineer B. MacOdrum	Polar Gas Limited
	D. Houde	Procureur général de la province de Québec
	R. Smith	Province of Ontario - Ministry of Energy
	I. McMahon	Shell Canada Limited
	L.H. Pilon M.A. Brown S. Trachimovsky	TransCanada PipeLines Limited
	A.G. Thomlinson	United Fishermen and Allied Workers Union
	F.H. Lamar K.J. MacDonald	National Energy Board
Vancouver	S. Wiltshire	Ashland Oil Canada Limited and Kitimat Pipe Line Ltd.
	T.R. Chantler	Canadian Scientific Pollution and Environmental Control Society
	G.F. Paschen	Canadians for Responsible Northern Development
	W.H. Fraser	Chevron Canada Limited
	V.C. Bell	Coalition Against Supertankers
	W.A. Esson R.B. Wallace	Council of Forest Industries of British Columbia
	R. Edwards	Government of British Columbia
	R.M. Perrin	Hudson's Bay Oil and Gas Company Limited
	G.E. Little	PanCanadian Petroleum Limited
	B.S. Redway	Private Individual

	D. Houde	Procureur général de la province de Québec
	M.A. Brown	TransCanada PipeLines Limited
	G. Irving	Trans Mountain Pipe Line Company Ltd.
	A.G. Thomlinson	United Fishermen and Allied Workers Union
	M.B. Pepper	Vancouver Board of Trade
	C.D. Williams P. Steele	Westcoast Transmission Company Limited
	F.H. Lamar K.J. MacDonald	National Energy Board
Halifax	G. Paschen	Canadians for Responsible Northern Development
	W. Denny	Government of New Brunswick
	L.D. Barry	Government of Newfoundland and Labrador
	T.S. Hoar	Home Oil Company Limited
	J. Dickey	Husky Oil Operations Ltd.
	S. Wiltshire	Kitimat Pipe Line Ltd.
	J.S. McKay L. Pasychny	Murphy Oil Company Ltd.
	W.W. Davidson	New Brunswick Electric Power Commission
	P. Armstrong	People, Tides and Energy
	F.D.W. Kelly	Port Hawkesbury Chamber of Commerce
	D. Houde	Procureur général de la province de Québec
	G. Evans G. Godsoe	Province of Nova Scotia

	P.J. Bates	Strait of Canso Industrial Development Authority
	W.J. MacLean	Town of Port Hawkesbury
	S. Trachimovsky M.A. Brown	TransCanada PipeLines Limited
	K.J. MacDonald	National Energy Board
Ottawa	F. Bregha	Canadian Wildlife Federation
	G. Paschen	Canadians for Responsible Northern Development
	D. Bogdasavitch	Department of Attorney-General - Province of Saskatchewan
	H. Fergusson	Dow Chemical of Canada, Ltd.
	J. Francis C. Campbell	DuPont of Canada Limited
	D.B. Brooks	Energy Probe
	R.J. Gibbs	Foothills Pipe Lines (Yukon) Limited
	S. Fisher	F.T. Fisher's Sons Ltd.
	J.-M. Fortier	Gaz Métropolitain, inc.
	R. Edwards	Government of British Columbia
	W.F. Denny	Government of New Brunswick
	L.D. Horne	Gulf Canada Limited
	R. Perrin	Hudson's Bay Oil and Gas Company Limited
	J. Dickey	Husky Oil Operations Ltd.

R. Walker	Imperial Oil Limited
G.M. Burden	Independent Petroleum Association of Canada
D. Scott	Industrial Gas Users Association
A.R. O'Brien J.D. McWilliams	Interprovincial Pipe Line Limited
S. Wiltshire F. Saville	Kitimat Pipe Line Ltd.
R.G. Farquharson	Murphy Oil Company Ltd.
J.J. Marshall	Norcen Energy Resources Limited
M.M. West W.S. Hunter	Ontario Hydro
J.L. Snith	Pacific Petroleums Ltd.
D.G. Hart	PanCanadian Petroleum Limited
J. Francis C. Campbell	Petrosar Limited
I.B. MacOdrum D. Trineer	Polar Gas Limited
J. Francis C. Campbell	Polysar Limited
D. Houde	Procureur général de la province de Québec
R.W. Macaulay R. Smith	Province of Ontario Ministry of Energy
G. Godsoe	Province of Nova Scotia
I. McMahon	Shell Canada Limited
F.J.C. Newbould	Sun Oil Company of Canada Limited

P.R. Carpenter W. Beaudry C. Neufeld	Texaco Canada Inc.
J.H. Farrell B.K. Singer	The Consumers' Gas Company and the Northern and Central Gas Corporation Limited
S. Trachimovsky M.A. Brown	TransCanada PipeLines Limited
J. Francis C. Campbell	Union Carbide Canada Limited
A. Thomlinson	United Fishermen and Allied Workers Union
F.H. Lamar K.J. MacDonald A. Bigué	National Energy Board

GLOSSARY OF TERMS

ABBREVIATION OF TERMS

API	American Petroleum Institute.
bbl.	barrels; 1 barrel is equal to 34.9723 Imperial gallons.
Bcf	billion (10^9) cubic feet.
Btu60/61	British thermal unit; the amount of heat required to raise the temperature of one pound of water 1 degree Fahrenheit from 60° to 61°.
CHIP	Canadian Home Insulation Program.
CPI	Consumer Price Index.
DOE	Department of Energy (United States).
EOV	East of the Ottawa Valley (Line).
FOB	Freight on Board.
GCOS	Great Canadian Oil Sands Ltd.
GNP	Gross National Product.
GPP	Gross Provincial Product.
LPG	Liquefied Petroleum Gases.
Mbbl.	Thousand barrels.
Mb/d	Thousand barrels per day.
Mcf	Thousand cubic feet.
MMcf	Million cubic feet.
MMstb	Million stock tank barrels.
NGL	Natural Gas Liquids.
Quad	Equal to 1 quadrillion Btu's. A quadrillion is equal to one million billion, i.e. 10^{15}.
RDP	Real Domestic Product.
Tcf	Trillion cubic feet.
ULCC	Ultra Large Crude Carrier.
VLCC	Very Large Crude Carrier.
WOV	West of the Ottawa Valley (Line).

ABBREVIATIONS OF NAMES

"AERCB"	- Alberta Energy Resources Conservation Board
"AGTL"	- The Alberta Gas Trunk Line Company Limited
"Alberta"	- Department of Energy and Natural Resources - Government of Alberta
"Alyeska"	- Alyeska Pipeline Service Company
"Amoco"	- Amoco Canada Petroleum Company Ltd.
"APEC"	- Atlantic Provinces Economics Council
"Ashland"	- Ashland Oil Canada Limited
"BCEC"	- British Columbia Energy Commission
"BP"	- BP Exploration Canada Limited
"British Columbia"	- Government of British Columbia
"Canadian Hidrogas"	- Canadian Hidrogas Resources Ltd.
"Canadian Wildlife"	- Canadian Wildlife Federation
"Chevron Canada"	- Chevron Canada Limited
"Chevron Standard"	- Chevron Standard Limited
"COFI""	- Council of Forest Industries of British Columbia
"COAST"	- Coalition Against Supertankers
"Consumers'"	- The Consumers' Gas Company
"CPA"	- Canadian Petroleum Association
"CRND"	- Canadians for Responsible Northern Development
"CTA"	- Canadian Trucking Association
"Dome"	- Dome Petroleum Limited
"Dow"	- Dow Chemical of Canada, Limited
"DuPont"	- DuPont of Canada Limited

"EMR"	-	Federal Department of Energy, Mines and Resources
"Fisher's"	-	F.T. Fisher's Sons Ltd.
"Foothills"	-	Foothills Pipe Lines (Yukon) Ltd.
"Gaz Métro"	-	Gaz Métropolitain, inc.
"Gulf"	-	Gulf Canada Limited
"HBOG"	-	Hudson's Bay Oil and Gas Company Limited
"Home"	-	Home Oil Company Limited
"Husky"	-	Husky Oil Operations Ltd.
"IGUA"	-	Industrial Gas Users Association
"Imperial"	-	Imperial Oil Limited
"Interprovincial" or "IPL"	-	Interprovincial Pipe Line Limited
"IPAC"	-	Independent Petroleum Association of Canada
"Kitimat"	-	Kitimat Pipe Line Ltd.
"Lakehead"	-	Lakehead Pipe Line Company, Inc.
"Manitoba"	-	Manitoba Energy Council
"McDaniel"	-	McDaniel Consultants (1965) Ltd.
"Mobil"	-	Mobil Oil Canada, Ltd.
"Murphy"	-	Murphy Oil Company Ltd.
"N.B. Power"	-	New Brunswick Electric Power Commission
"New Brunswick"	-	Government of New Brunswick
"Newfoundland"	-	Department of Mines and Energy, Government of Newfoundland and Labrador
"Norcen"	-	Norcen Energy Resources Limited
"Northern and Central"	-	Northern and Central Gas Corporation Limited
"Nova Scotia"	-	Nova Scotia Energy Council and the Province of Nova Scotia

"Ontario"	-	Ministry of Energy, Government of Ontario
"OSSA"	-	The Oleophilic Sieve Society of Alberta
"Pacific"	-	Pacific Petroleums Ltd.
"Panarctic"	-	Panarctic Oils Ltd.
"PanCanadian"	-	PanCanadian Petroleum Limited
"Petalta"	-	Petrochemicals Alberta Project
"Petrofina"	-	Petrofina Canada Ltd.
"Petrosar"	-	Petrosar Limited
"Polar"	-	Polar Gas Limited
"Polysar"	-	Polysar Limited
"Portland-Montreal"	-	Portland-Montreal Pipeline System
"PTE"	-	People, Tides and Energy
"Quebec"	-	Ministry of Natural Resources, Government of Quebec, and Ministry of Industry and Commerce, Government of Quebec
"Rainbow"	-	Rainbow Pipe Line Company, Ltd.
"Saskatchewan"	-	Department of the Attorney General, Province of Saskatchewan
"SCIDA"	-	Strait of Canso Industrial Development Authority
"Shell"	-	Shell Canada Limited
"Smithers"	-	Smithers Conservation Centre
"SPEC"	-	Canadian Scientific Pollution and Environmental Control Society
"SOS"	-	The North Coast Committee to Save Our Shores
"Sun Oil"	-	Sun Oil Company of Canada Limited

"Texaco"	-	Texaco Canada Inc.
"TransCanada" or "TCPL"	-	TransCanada PipeLines Limited
"Trans Mountain"	-	Trans Mountain Pipe Line Company Ltd.
"TMOPLC"	-	Trans Mountain Oil Pipe Line Corporation
"UBCIC"	-	Union of B.C. Indian Chiefs
"UFAWU"	-	United Fishermen and Allied Workers Union
"Union"	-	Union Gas Limited
"Union Carbide"	-	Union Carbide Canada Limited
"Westcoast"	-	Westcoast Transmission Company Limited
"Worldwide"	-	Worldwide Energy Company Ltd.

EXPLANATION OF TERMS

°API - Degree(s) API. A relative measure of the specific gravity of crude oils. Crude oils with a higher value of °API have a lower specific gravity.

Bitumen - A naturally occurring viscous mixture composed mainly of hydrocarbons heavier than pentane which may contain sulphur compounds and that in its natural state is not recoverable at a commercial rate through a well.

Blowdown - The production of gas either from the gas cap of an oil reservoir normally after depletion of the oil, or from a cycled gas pool upon cessation of the cycling operation.

CANDIDE - A large computerized econometric model of the Canadian economy which has been developed by the Economic Council of Canada with the assistance of several departments of the Federal Government. The development of the model has been proceeding since 1970, and the current version, CANDIDE 1.2M, was developed in 1976. The model being used at the Board is the 1.2M version with further modifications made by Board staff.

Carbon Dioxide ("CO_2") Flooding- A tertiary recovery process in which carbon dioxide is injected into the reservoir under conditions which result in the injected material mixing with the reservoir fluid.

Chemical Flooding - A tertiary recovery process in which water with added chemicals is injected into a petroleum reservoir. Three of the common groups of chemicals which may be added are surfactants, polymers, and alkaline chemicals.

Condensate - As used herein, synonymous with pentanes plus.

Conventional Areas - Those areas of Canada which have a long history of oil production. The term "conventional" also refers to those reservoirs from which, in their natural state, oil will flow to a wellbore in commercial quantities.

Conventional Recovery - Crude oil recovery from a petroleum reservoir resulting from primary recovery, infill drilling, or waterflood.

Crude Oil and Equivalent Hydrocarbons - Sometimes referred to as "Crude Oil and Equivalent". Includes crude oil, synthetic crude oil produced from oil sands plants, and pentanes plus.

Cycling Gas Pool - A natural gas pool from which the natural gas produced is processed to remove one or more of the components of the natural gas stream and is reinjected into the same pool to maintain reservoir pressure and enhance liquid recovery from the pool.

Elasticity - In relation to demand, a measure of the responsiveness of demand for a product to a change in values of the variables affecting demand.

Enhanced Recovery - See "Recovery".

Established Reserves - Those reserves, both naturally occurring and synthetic, which on the basis of identified economic considerations and within a specified time frame, are considered to be recoverable with a high degree of certainty from known reservoirs, through the application of currently accepted recovery techniques.

Feedstock - Raw material supplied to a refinery or petrochemical plant.

Frontier Reserves - Reserves of crude oil in the offshore areas, the High Eastern Arctic region, and the Mackenzie Delta-Beaufort area.

Heavy Crude Oil - A term loosely applied to crude oils with a low API gravity. For a more detailed explanation of the National Energy Board's classification of heavy crude oil see Appendix K.

Hog Fuel - Fuel consisting of bark, shavings, sawdusts and low grade lumber and lumber rejects that result from the operation of pulp mills, sawmills and plywood mills.

Improved Recovery - See "Recovery".

Infill Drilling - The process of drilling additional wells in a producing field, thereby reducing the spacing of wells.

In Situ Recovery - With reference to oil sands deposits, the use of techniques to recover bitumen without the necessity of mining the sands.

International Price of Crude Oil - A generalization for the "going price" of crude oil in the world markets.

Light Crude Oil - A term applied to crude oils with a high API gravity. Generally, the light crude oil category includes all crude oil and equivalent hydrocarbons not included in the definition of heavy crude oil.

Micellar Flooding - An enhanced recovery process in which a fluid containing a molecular aggregate, generally of molecules that can attach themselves to both oil and water makes the oil and water quasi-miscible.

Middle Distillates - The range of refined petroleum products which includes kerosene, stove oil, diesel fuel, and light fuel oil.

Miscible Flooding - An enhanced recovery process in which a substance that promotes miscibility between water and oil is used. This substance acts to destroy the interface between the fluids and reduces active capillary forces.

Northern Tier Refineries - A general term which refers to refineries located in states bordering on Canada which have in the past been dependent on Canadian crude. This term is often used interchangeably with the term "Priority 1 Refineries".

Oil Sands - Deposits of sand and other rock aggregate which contain bitumen. As used in this report, includes Athabasca, Buffalo Head Hills, Cold Lake, Peace River, and Wabasca deposits. See also "Bitumen".

Original Oil in Place - See "Recovery".

Pentanes Plus - A volatile hydrocarbon liquid composed primarily of pentanes and heavier hydrocarbons. Generally, a by-product obtained from the production and processing of natural gas.

Potential Producibility - The estimated average daily ability to produce that could be achieved on ninety days notice, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing, and pipeline capacity.

Recovery

- Original Oil in Place - The total calculated volume, prior to any production, of crude oil within a discovered petroleum reservoir, of which only a portion is recoverable.

- Primary Recovery - Crude oil recovery from a petroleum reservoir as a result of the natural energy of the reservoir moving the crude oil toward producing wells.

- Secondary Recovery - The additional crude oil recovery from a petroleum reservoir obtained by supplying energy to supplement or replace the energy of primary recovery. Generally, the term refers to already technically and economically proven methods such as waterflooding, gas injection, and steam injection.

- Tertiary Recovery - The additional crude oil recovery from petroleum reservoirs through the application of third generation methods. These methods are the newer, less technically proven techniques such as the thermal processes, carbon dioxide flooding, hydrocarbon miscible flooding, and chemical flooding.

- Improved or Enhanced Recovery - General terms used to include all crude oil recovery from a petroleum reservoir which is incremental to primary recovery.

Requirements for Indigenous Feedstocks - Total requirements WOV plus required deliveries to Montreal and the area EOV.

Reserve Appreciation - Growth in the reserves credited to a pool or area due to additional delineation of reservoirs through development drilling or the application of improved recovery methods.

Scenario - A set of hypothetical conditions or relationships. In this report, "scenarios" are used to examine the effect which certain combinations of assumptions with regard to economic growth and crude oil prices have on the supply and demand for energy. In all of the cases, it is assumed that Canadian crude oil prices will approach the international level by 1981. In addition, each case is characterized by the following underlying assumptions:

- Low Demand Case - the Canadian economy is assumed to expand in accordance with a medium projection of economic growth while world oil prices are assumed to increase in real terms at an annual rate of about five percent.

- Base Demand Case - the Canadian economy is assumed to expand in accordance with a medium projection of economic growth while world oil prices are assumed to remain constant in real terms.

- High Demand Case - the Canadian economy is assumed to expand in accordance with a high projection of economic growth while world oil prices are assumed to decline in real terms at an annual rate of about five percent.

. Low, Base, and High Supply Cases - Assumptions regarding the four factors that determine the supply cases are discussed at the beginning of Chapter 2.

Self-reliance - Self-reliance in energy can be measured by the degree to which Canada is independent of imported oil from insecure sources. The Government has defined this as limiting imports to either one-third of Canada's feedstock requirements or 800 Mb/d, whichever is less.

Shut-in Capacity - The unused production capability of currently producing oil and gas wells or shut-in oil and gas wells whether or not they are connected to surface gathering and producing facilities plus the known production capability of proved oil and gas pools not presently on production.

Stock tank barrel - One barrel of gas-free oil at the surface of the ground. Oil in the reservoir contains dissolved gas and the volume in solution depends upon several factors. However, at surface conditions of ambient temperature and atmospheric pressure, the solution gas is released and the volume of liquid decreases. Unless otherwise stated, use of the word "barrel" in this report implies a stock tank barrel.

Syncrude Canada ("Syncrude") - A consortium formed to develop a mining plant and bitumen upgrading facility in the Athabasca oil sands. At present this group consists of Imperial Oil Limited, Gulf Oil Canada Limited, Canada-Cities Service Ltd., Petro-Canada and the Governments of Alberta and Ontario.

Synthetic Crude Oil - Crude oil produced through treatment of bitumen in upgrading facilities designed to decrease its viscosity and sulphur content. See also "Bitumen".

Straddle Plants - A natural gas processing plant in which gas is further processed, subsequent to field processing, to remove liquid components. Generally, the plant is located on a main transmission system and is said to "straddle" the pipeline.

Tertiary Recovery - See "Recovery".

Tailings Pond - A body of water used to settle out solid wastes from water that has been used in a mining operation.

Thermal Processes - Tertiary recovery processes in which heat is added to the reservoir. Two principal thermal processes are steam flooding and in situ combustion. In steam flooding, steam is injected into the reservoir. In situ combustion involves ignition of oil in the reservoir and burning a portion of the oil in place to generate heat.

Waterflooding - The process of injecting water into a reservoir for the purpose of displacing oil towards a production well. See also "Recovery".

Wellhead - Specifically, the equipment placed on top of a well at the surface to maintain control of the well. More generally, it is used to specify a delivery point in the crude oil production system, e.g., the wellhead price.

World Price - See "International Price".

METRIC CONVERSION TABLE

1 barrel	=	0.1589873 cubic meters*
1 inch	=	0.0254 meters
1 foot	=	0.3048 meters
1 mile	=	1.609344 kilometers
1 $Btu_{60/61}$	=	1054.615 joules
1 quad	=	1.054615×10^9 gigajoules
1 psi	=	6.894757 kilopascals
1 ton (2240 lbs.)	=	1.016047 metric tons
1 horsepower (electric)	=	0.746 kilowatts

* In the conversion of oil volumes from 60°F to 15°C (59°F), a correction must be made because of thermal expansion which varies with API gravity. The above conversion factor must be multiplied by the following correction factors to reflect API gravities:

API Gravity	Volume Correction Factor
0 - 6	0.9997
7 - 35	0.9996
36 - 51	0.9995
52 - 64	0.9994
65 - 78	0.9993
79 - 91	0.9992
92 - 99	0.9991

CHAPTER 1

SUMMARY AND CONCLUSIONS

The Minister of Energy, Mines and Resources, in his letter to the Board of 16 January 1978, indicated his concern about Canadians being exposed to possible medium or long-term shortages of imported oil. He noted, as well, that under some projections, Canada may be faced with the difficult decision of how inadequate oil supplies might be allocated between eastern and western market areas. He concluded by requesting the Board, under Section 22(2) of its Act, to investigate and report to him on a range of possible oil supply situations over the course of the next 10 to 15 years and on the dependency on imports that might develop for British Columbia and eastern Canadian consumers. In situations where significant imports would be required, the Board was asked to comment on the size, location, and timing of petroleum ports of entry. A copy of the Minister's letter is provided as Appendix A of this report.

In order to assure itself that the report would be as exhaustive as possible, the Board decided to hold a public inquiry so that all interested parties would have the opportunity to be heard, and to provide the Board with a broad base of fact and opinion on the subjects under consideration. In response to the Board's Order, which is included as Appendix B, 79 written submissions were received. Furthermore, viva voce evidence was presented to the Board in Calgary, Vancouver, Halifax, and Ottawa from 66 submittors. In preparing its forecasts, the Board has analyzed the evidence received and this has been given appropriate weight in the Board's estimates.

This report addresses the matters raised by the Minister as well as other matters that appear important to the Board. Its structure is similar to that of the Board's last report on oil matters issued in February, 1977 entitled "Canadian Oil Supply and Requirements", except that chapters have now been included on self-reliance and on ports of entry and oil pipeline facilities. Appendices, where applicable, have been reported in both Imperial and metric units.

In view of the uncertainties inherent in forecasting, the Board has again adopted a method of estimating ranges instead of relying on "point" forecasts. However, although "High" and "Low" oil supply and demand estimates are included, detailed presentation of the results is restricted to only one forecast, referred to as the "Base Case". In addition, mention is often made of the "forecast period"; this term refers to the period from 1978 to 1995.

The main conclusions of this report are:

1. There should be no need for augmenting existing oil importing capability through 1995. This is predicated on the supply-demand balance being as shown in the Board's base forecast, on the expeditious development of the oil sands, and on the development of conventional crude oil being sustained. No assessment of possible new oil import facilities is necessary at this time.

2. Deliveries of Canadian crude oil to Montreal should not be at such a high level as to jeopardize the long-term viability of the Portland-Montreal pipeline system. The present capacity of the Sarnia-Montreal pipeline, without additional investment in facilities, is approximately 315 Mb/d, and throughputs not exceeding this level would be compatible with the objective of maintaining sufficient deliveries by the Portland-Montreal pipeline to keep it in service.

3. Deliveries of Canadian oil to Montreal could be sustained at the 315 Mb/d level until late 1983; deliveries would have to be reduced gradually thereafter, reaching a level of about 100 Mb/d by 1995.

4. Licensing of exports of light crude oil can be maintained at the 1978 level of 55 Mb/d for three additional years.

5. Exports of heavy crude oil should continue to be licensed on the current basis, i.e., restricted to those quantities remaining after meeting the feedstock requirements of Canadian refiners.

6. If there were significant displacement of oil by natural gas in Eastern Canada, the surplus refining situation already existing in that area would be exacerbated; markets for the displaced oil products may not easily be found.

A summary of the report, by chapter, follows. Where applicable, a comparison between the current Board findings and those contained in the February, 1977 report is also provided.

Reserves and Producibility of Crude Oil and Equivalent

The forecast supply of crude oil and equivalent hydrocarbons derives from five sources: established reserves in conventional areas, additions to established reserves in conventional areas, pentanes plus reserves, oil sands deposits, and frontier reserves.

In preparing its current estimates of reserves and producibility from established reserves, the Board examined in detail 180 units and pools comprising 84 percent of the total established oil reserves in the Western Canadian Sedimentary Basin. The Board estimates that as of 1 January 1978 established remaining recoverable reserves of light crude oil are 5000 million stock tank barrels. It also estimates that additions to reserves from new discoveries for light crude oil in Western Canada will be 1.3 billion barrels including 0.5 billion barrels of recoverable oil for West Pembina. Furthermore, the Board expects that recoverable reserves of this grade of oil will be further increased by nearly 1 billion barrels as a result of improved recovery techniques.

Potential producibility of light crude oil from established reserves is expected to decline from 1,389 Mb/d in 1978 to 606 Mb/d in 1985, while producibility from reserves additions is expected to increase from 14 Mb/d in 1978 to 151 Mb/d in 1985.

The Board estimates that as of 1 January 1978 the established remaining recoverable reserves of heavy crude are 783 million stock tank barrels. The Board believes that an additional 400 million barrels of reserves will arise from new discoveries. Also, it has incorporated 420 million barrels from development of known oil in place in the Lloydminster area and 1750 million barrels of reserves additions resulting from improved recovery techniques.

Potential producibility from established reserves of heavy crude oil is expected to decline from 208 Mb/d in 1978 to 104 Mb/d by 1985. However, producibility from reserves additions during the same period is expected to increase from 9 Mb/d to 76 Mb/d.

The Board's forecast of pentanes plus production from established reserves and reserves additions is only marginally higher than the forecast published in its last report.

The Board's current estimate of oil sands development approaches the maximum development scenario shown in the 1977 Oil Report. In adopting this schedule, the Board emphasizes that realization of this forecast depends on a realistic attitude to sharing of the revenue from these developments by industry and by the Alberta and Federal Governments. It is the Board's view that the Canadian oil supply-demand situation is such that oil sands development appears highly desirable in order to offset an ever-increasing reliance on imported crude oil. Increasing imports are detrimental to Canada's balance of trade and security of supply and, unless curbed, would require expansion or construction of import facilities.

With regard to the frontier areas, the Board believes that it would be too speculative at this time to predict reserves additions or to project oil supply from these areas during the forecast period.

A comparison of the Board's current forecast of potential producibility with that contained in its last oil report is shown below:

Potential Producibility (Mb/d)

	Estimated 1978	February, 1977 Report 1985	February, 1977 Report 1995	September, 1978 Report 1985	September, 1978 Report 1995
Light Crude Oil					
Established Reserves	1389	543	181	606	196
Reserves Additions	14	63	114	151	195
Heavy Crude Oil					
Established Reserves	208	85	28	104	37
Reserves Additions	9	74	90	76	166
Pentanes Plus	129	87	44	102	48
Oil Sands	77	200	575	255	755
Frontier	-	-	-	-	-
Less: Upgrading Loss	-	-	-	(5)	(5)
TOTAL	1826	1052	1032	1289	1392

Demand for Total Energy

The Board prepares its estimates of the demand for refined petroleum products within the context of a review of demand for other energy forms. This total energy forecast methodology was described in some detail in the 1977 report.

Energy demand in the residential, commercial, and industrial sectors is linked to population, energy prices, and selected economic variables. In the transportation sector, demand is estimated separately for each of the main transportation modes, namely air, rail, marine, and road. Separate estimates are also made for the different groups of non-energy use of hydrocarbons, including the demand for petrochemical feedstocks. A comparison between the Board's forecast of energy demand growth rates by sector and the forecasts of submittors is made in Table 3-9.

The forecast of the economic variables is based on the CANDIDE econometric model of the Canadian economy. During the period 1975-1980, the Board's forecast assumes that the economy will grow at an average annual rate of 4.3 percent, increasing to 4.5 percent in the period 1980 to 1985, and declining to about 3.6 percent during the next ten years of the forecast period. Projections of other economic and demographic variables used by the Board in preparing its forecast are contained in Tables 3-2 and 3-3.

The Board assumes that the world price of crude oil will remain constant in real terms at its 1977 level, and the domestic price of crude oil will approach the world level by the end of 1981. The forecast is based on the assumption that the city-gate price of natural gas in Toronto will increase in parallel with the price of domestic crude oil, maintaining the present relationship of approximately 85 percent of the crude oil price on a Btu equivalent basis. It should be emphasized that these and other price assumptions represent the Board's assessment of the future direction of prices based on policies and conditions existing at the time of the inquiry.

The Board expects total primary energy demand in Canada to increase from 8.8 quads in 1978 to 10.8 quads in 1985 and to 14.3 quads in 1995. Although there is little difference between the current forecast for total primary energy demand and that presented in the 1977 Oil Report, oil's share is somewhat lower in the present forecast. This is mainly because of increased market penetration by

other energy forms. With respect to the total primary energy demand forecast contained in the Board's report of July 1977 entitled "Reasons for Decision - Northern Pipelines", that forecast was higher than the current forecast largely as a result of the evidence during that hearing indicating a higher growth in the economy than now anticipated, and a greater share of the energy market held by electricity than now assumed.

Demand for Refined Petroleum Products

The Board is forecasting total refined petroleum product demand to grow by an average of 1.4 percent annually, reaching 2190 Mb/d in 1995. The growth in demand during the forecast period is expected to slacken gradually as a result of increasing energy prices, lower economic growth, interfuel substitution, and conservation measures.

The Board expects gasoline demand to peak in 1980 and to decline thereafter mainly because of improved fuel economies, a trend to smaller cars, consumer response to price increases and the substitution of diesel fuel for gasoline in new automobiles and trucks. The demand for light fuel oil, kerosene, and stove oil is also expected to decline throughout the forecast period primarily as a result of higher energy prices, conservation programs, improved efficiencies of home oil heating equipment, and increased penetration by natural gas and electricity. Heavy fuel oil demand is anticipated to show only limited growth, reflecting higher energy prices, lower growth in industrial economic activity, interfuel substitution, and reduced requirements for electricity generation.

The Board notes that all of the submittors who provided detailed demand data for all regions of Canada forecast total refined product demands to be lower than the corresponding forecasts made at the previous hearing. An overview of the submittors' forecasts by product and a comparison with the Board's estimates are provided in Section 4.2.

A comparison between the present projection for refined petroleum product sales and that contained in the Board's 1977 Oil Report is provided in the following table.

REFINED PETROLEUM PRODUCT SALES - CANADA[1]

(Mb/d)

	Estimated 1978	February 1977 Report		September 1978 Report	
		1985	1995	1985	1995
Motor Gasoline	641	677	637	638	601
Light Fuel Oil, Kerosene and Stove Oil	294	334	360	270	265
Diesel Fuel Oil	215	279	375	283	419
Heavy Fuel Oil	295	425	487	333	367
Petrochemical Feedstocks	71	115	212	137	160
Other Products	219	269	360	285	379
TOTAL	1734	2099	2431	1945	2190

(1) Totals may not add because of rounding.

Requirements for Feedstocks

Estimates of Canadian requirements for both foreign and indigenous feedstocks were derived by forecasting such elements as the demand for petroleum products in Canada, the degree of refinery utilization and flexibility, the industry's own use and loss of feedstocks, the level of imports, regional transfers, and exports, and the use of feedstocks from natural gas plants.

The Board's forecast of requirements for crude oil and equivalent is compared graphically with submittors' forecasts in Figures 5-1, 5-2, and 5-3.

Crude oil refining capacity in the area EOV, excluding the mothballed Come by Chance refinery, is expected to be more than sufficient to meet local product demands until after 1995. The Board assumes that feedstocks will be refined in the area at levels adequate to meet not only most domestic demands for products, but also a continuing volume of exports. There appears to be no ready solution to the problems arising from surplus refining capacity which results in inadequate refining returns and which could result in plant closures.

WOV refining capacity additions will likely be required in the Prairies and/or British Columbia during the later part of the forecast period. In Ontario, capacity is expected to be sufficient until at least 1995. The Board has assumed that refineries will be run to meet light oil demand, and consequently, some regional surpluses and deficits of heavy fuel oil are contemplated.

Indigenous oil requirements were estimated by grade of oil. The Board based its estimate of refiners' requirements for heavy crude oil largely on its forecast of demand for asphalt. Synthetic crude oil demand was projected assuming Canada's entire production would be consumed domestically. Pentanes plus requirements were estimated taking into account refinery use for petrochemical manufacture. Further discussion on the anticipated demand for these types of oil can be found in sections 5.4 and 5.5 of the report.

The Board recognizes that the refining industry faces numerous problems associated with variations of feedstock supply, surplus capacity, and changes in the mix of product requirements. The Board holds the view that although some investment in new equipment would be necessary, given a reasonable period of adjustment and the requisite flexibility to adapt to changing circumstances, the refining industry is capable of supplying products needed in Canada from available crude oil. On the basis of the evidence before it, the Board also believes that an increasing supply of synthetic crude oil will not likely pose insuperable refining problems.

A comparison of the Board's current forecast of feedstock requirements for crude oil and equivalent with that contained in the Board's February 1977 report is provided below, broken down by demand east and west of the Ottawa Valley.

REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

(Mb/d)

	Estimated 1978	February 1977 Report		September 1978 Report	
		1985	1995	1985	1995
EOV	850	956	1079	918	996
WOV	995	1240	1405	1131	1301
TOTAL	1845	2196	2484	2049	2297

Self-Reliance and Security of Supply

The Board finds that in its base case, refiners located WOV should be able to continue operating on indigenous supplies of crude oil until after 1995. Furthermore, some domestic crude oil should continue to be available for delivery to Montreal. However, should a maximum dependency situation develop, i.e., where there would be low supply and high demand, refiners located WOV would require imported crude oil in significant quantities even if deliveries of Canadian feedstocks to Montreal were terminated. It seems to the Board, therefore, that with the current outlook, the Portland-Montreal pipeline system must be maintained in service for security of supply reasons. This can be shown for 1985 as follows:

1985 CALCULATION OF EXCESS CAPACITY OF EXISTING OIL IMPORT FACILITIES

(Mb/d)

	Minimum Dependency	Base Dependency	Maximum Dependency
WOV Requirements	1042	1131	1244
Plus: Montreal Requirements	508	550	614
Sub-Total	1550	1681	1858
Indigenous Supply	1599	1394	1223
Plus: Existing Capacity of Portland - Montreal Pipeline	550	550	550
Sub-Total	2149	1944	1773
Excess Capacity of Existing Facilities	599	263	(85)*

* Figure in brackets represents a deficiency.

On the basis of information and evidence provided, the Board accepts that there is considerable potential for interfuel substitution among all energy forms. The ability of gas to contribute to self-reliance through substitution for oil will be a function of any changes in its ability to compete with petroleum products in existing and new market

areas. Market dislocations could create problems for Eastern Canadian refiners now operating at less than optimum capacity. Additional export markets for petroleum products, if achievable, would assist in the transition.

With respect to the use of renewable energy, the Board recognizes that over the long run, alternative renewable energy sources could contribute significantly to Canada's energy supply. The five-year, $380 million program recently announced by the Minister of Energy, Mines and Resources will provide further incentives for the development and use of renewable energy resources, which could result in the Board's present forecast of such use being conservative.

Considerable evidence was received by the Board on the impact on self-reliance of upgrading heavy crude oil into lighter, more usable feedstocks for Canadian refiners. There was no consensus among submittors on this matter. The Board is inclined to the view that the volume of heavy crude oil expected to be available during the forecast period could be sold in the domestic and export markets without the construction of an upgrading facility. If an upgrading facility were constructed, however, a more certain year-round market would be available and additional development of heavy crude oils would be encouraged. Based on the evidence, it appears that upgrading will cost between $4.00 and $6.00 per barrel and present price differentials in Canada between light and heavy crude oils will be less than this amount. While achieving appropriate differentials would be important to support upgrading, it should be recognized that any reduction in the returns to producers would have an offsetting negative impact on the economics of heavy oil development.

On balance, the Board has assumed, for its oil supply base case, that an upgrading plant will be built with an input capacity of 50 Mb/d to come on stream in 1985.

Ports of Entry and Oil Pipeline Facilities

The Board concludes that in providing for its oil requirements during the next decade and a half, Canada should place emphasis on the expeditious development of its oil sands while sustaining the development of conventional oil. If this takes place, it appears to the Board that there should be no need to expand or augment existing facilities for the importation of overseas oil.

Chapter 7 contains a discussion on the existing oil importation and pipeline systems, and potential for possible expansions and additions on both the east and west coasts.

Determination of Export Volumes

In the interests of giving Canadian producers of light crude oil a clearer outlook as to likely future export levels, the Board sees merit in licensing these exports at a constant rate for the period 1979 - 1981 inclusive. Such an export program would also provide a more certain supply projection for the United States Northern Tier refiners, thus assisting them in making alternative supply arrangements. The Board believes that a continuation of the 1978 level of light crude licensed exports at 55 Mb/d would be reasonable. It is anticipated that exports of light crude oil would cease after 1981 except for oil that is exported under exchange arrangements and oil that due to grade or geographic locations is limited to use by customers in the United States, and subject, of course, to any unforeseen developments in Canadian supply and demand.

As to heavy crude oil surpluses, the Board intends to continue its present procedure of licensing, on a quarterly basis, exports of those quantities remaining after meeting the feedstock requirements of Canadian refiners. In determining the surplus, the Board will not include in projected Canadian demand the feedstock required for an upgrading plant until such a plant is in operation. This will benefit producers by providing for continuity of production through exports to Northern Tier refiners until the heavy crude oil is needed by the upgrading plant.

In the case of refined petroleum products, the Board will continue to recognize in licensing that some refinery capacity was built to process foreign crude oil for the export market. As to exports from that area of Canada processing indigenous crude oil, the Board intends to follow regulatory procedures compatible with the long-term objective of achieving energy self-reliance, but at the same time, will have regard for the refining and marketing conditions existing at the time an application is being considered.

Furthermore the Board believes that where satisfactory arrangements can be made, refiners with spare capacity should be encouraged to refine United States or overseas crude oil to supply products for the United States market.

CHAPTER 2

RESERVES AND PRODUCIBILITY OF CRUDE OIL AND EQUIVALENT

2.1 INTRODUCTION

This section of the report deals with the views received from the submittors as well as the Board's views concerning all matters related to Item 1a and Item 4 of the Board's Hearing Order OHR-1-78, which is appended to this report as Appendix B. Matters that fall into these areas are described more fully in the Board's Outline for Submissions under the heading "Reserves and Producibility of Canadian Oil."

In this Chapter the various oil supply categories are discussed in the following order:

- established reserves in conventional areas;
- additions to established reserves in conventional areas;
- pentanes plus;
- oil sands deposits;
- frontier reserves;
- summary of potential producibility forecasts;
- range of producibility scenarios.

The forecasting of future reserves additions and producibility is by nature speculative and subject to widely differing opinions, even among experts, as can be seen in the various supply sections that follow. In making its judgement on a most-likely supply scenario, or base case, the Board has considered all of the information and expert advice available to it through the public inquiry, the knowledge of its staff of petroleum engineers and geologists, and its own knowledge.

To better illustrate the range of uncertainty surrounding the Board's base case, the Board considers it necessary to show a minimum or "low", and a maximum or "high" supply case for each of the supply sources. This approach was used in the Board's February 1977 Report on Canadian Oil Supply and Requirements, and is continued in this report.

Four factors are distinguished as main determinants of future developments in supply, the relative significance of each differing greatly from one supply category to another. The four factors are:

- Geological Limitations. These determine the probability of the resource being present and in what volume. This would be the controlling factor, for example, in forecasting crude oil discoveries. For the base case, the ultimate reserves included are those that are considered on geological grounds to have at least a 50 percent or better probability of existing. For the low case, a 90 percent probability is used, and for the high case, a 10 percent probability is employed.

- Technological Limitations. These influence the accessibility of resources for exploitation, the level of recovery from deposits, and the lead times required for development. This factor could be dominant for some types of enhanced-recovery or in the production of frontier crude oil. For the base case, a gradual improvement in current technology is assumed, but the Board does not assume, for example, dramatic technological breakthroughs for processes that are now in the stage of laboratory investigation, but for which no field experimentation has commenced. For the low case, no significant technological advances are assumed; however, for the high case, major technological breakthroughs are envisaged.

- Crude Oil Prices. These can affect the rate of resource exploitation and can influence recovery levels. For all cases, it is assumed that domestic prices will approach the international level by the end of 1981. For the base case, it is assumed that the international price will remain constant in real terms, i.e., that future international price increases will vary with inflation rates. For the high case, it is assumed that international prices will increase by five percent annually in real terms, and in the low case, it is assumed that international oil prices will stay near current levels, i.e., they will decrease in real terms.

- Governments' Policies. These can affect development through availability of permits and licences, through regulations governing exploration and production practices, through regulations affecting the availability of export and domestic markets for a crude oil stream, and through the rates and conditions of royalties and taxes that affect the net return to the producer.

2.2 ESTABLISHED RESERVES IN CONVENTIONAL AREAS

2.2.1 Views of Submittors

With regard to the reserves and producibility from established pools, the Board received information on 220 individual units, pools, and pool groupings from industry sources and provincial agencies. The information was submitted on a detailed form provided by the Board to all submittors. This form, which is included in Appendix B, contained a section for a producibility forecast, a section for detailed reservoir data, and a section for reporting potential reserves additions for the producing properties. 180 units and pools, comprising 84 percent of the total established reserves in the conventional producing areas of Canada were examined in detail. The remaining pools, comprising 16 percent of the established reserves base, were divided into 40 pool groupings and assigned a producibility characteristic reflecting their combined historical producing capability and parameters similar to comparable pools in the area.

In addition to the individual pool reserves estimates submitted, reserves summaries were submitted by the CPA and by the provinces. The estimates of established remaining recoverable reserves as of 1 January 1978 are in Table 2-1.

Table 2-1

ESTABLISHED REMAINING RECOVERABLE RESERVES OF CONVENTIONAL LIGHT AND HEAVY CRUDE OIL AS OF 1 JANUARY 1978

Comparison of Estimates

(Millions of Barrels)

	CPA	Provinces	NEB
Territories	37.7	29.7	37.9
British Columbia	127.3	166.8	145.8
Alberta	5150.2	5223.0	4888.2
Saskatchewan	613.0	638.3	659.3
Manitoba	33.0	51.2	45.3
Ontario	9.6	7.9*	6.2
	5970.8	6116.9	5782.7

* Average of CPA and NEB estimates, Provincial estimate not available.

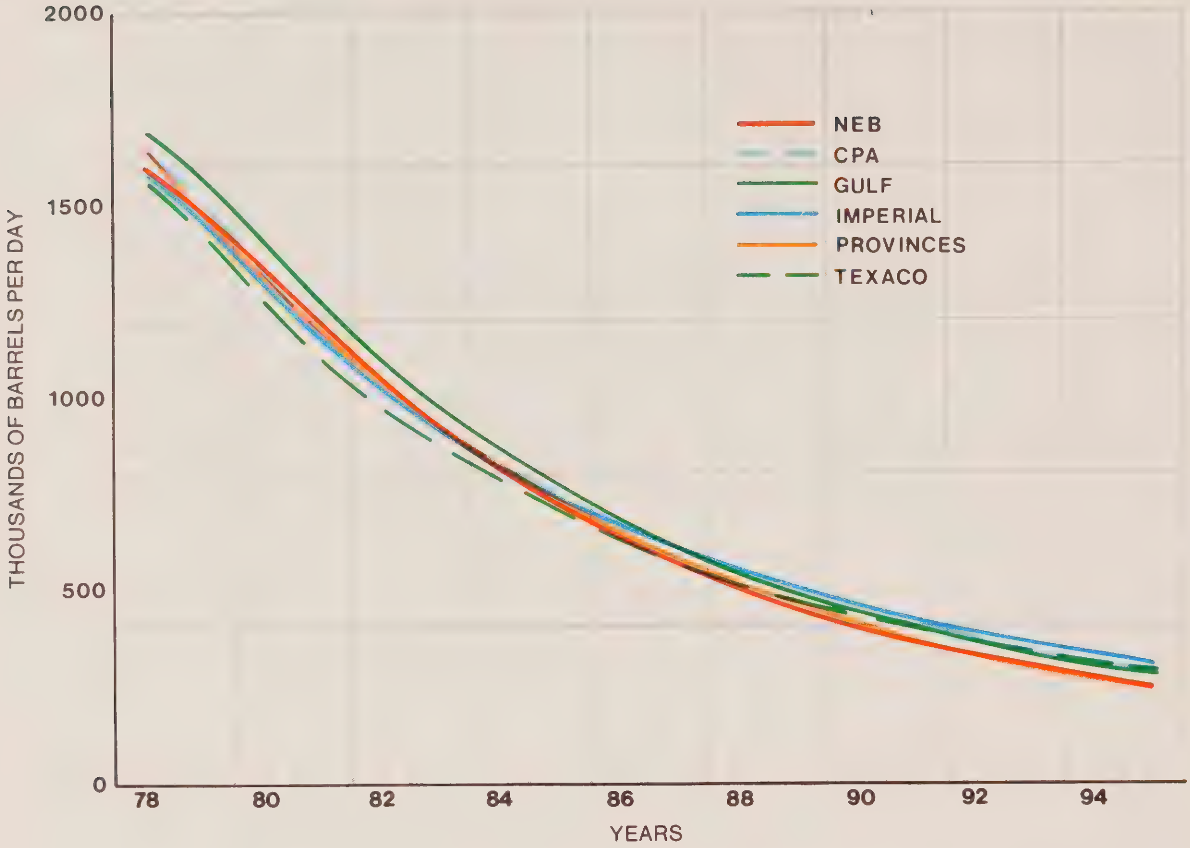


Figure 2-1 **POTENTIAL PRODUCIBILITY FROM ESTABLISHED RESERVES Comparison of Forecasts**

In addition to individual pool potential producibility forecasts provided by operators and provincial regulatory agencies, summaries of total producibility from established remaining recoverable reserves were provided by the CPA, Imperial, Gulf, Texaco, and the Provinces of Alberta, British Columbia, and Saskatchewan .

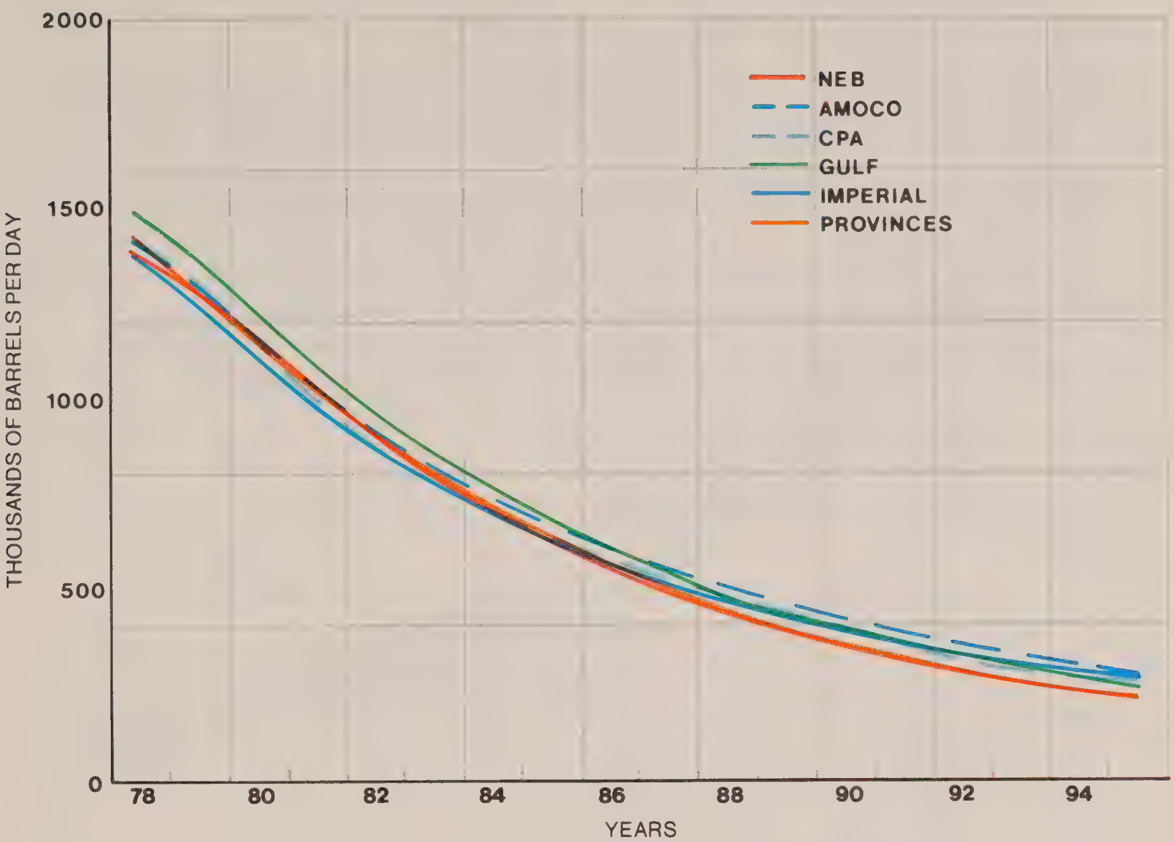


Figure 2-2 **POTENTIAL PRODUCIBILITY OF LIGHT CRUDE OIL FROM ESTABLISHED RESERVES**
Comparison of Forecasts

A comparison of the potential producibility forecasts is made in Figure 2-1. The submitted forecasts show a maximum difference of about 150 Mb/d in the early years of the forecast, declining to approximately 65 Mb/d at the end of the forecast period.

Some submittors provided separate forecasts for light crude oil and heavy crude oil. These forecasts are compared graphically in Figures 2-2 and 2-3 respectively.

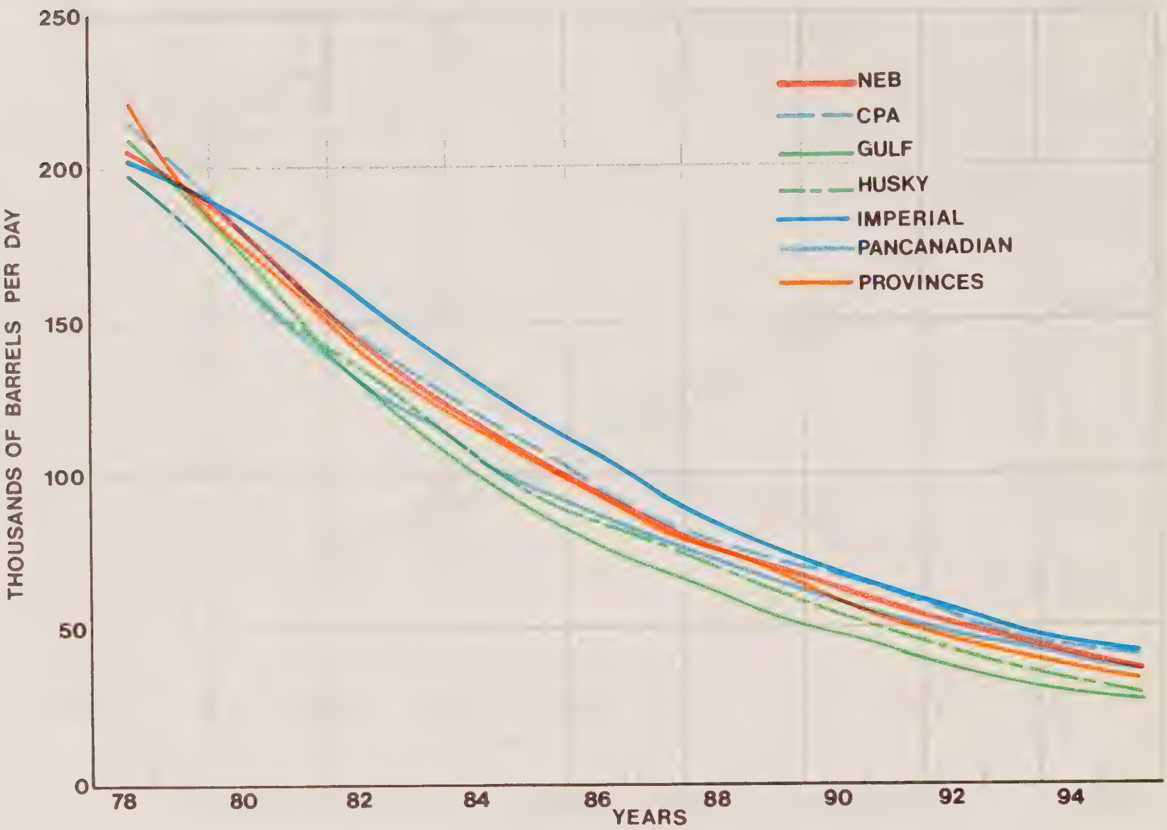


Figure 2-3 **POTENTIAL PRODUCIBILITY OF HEAVY CRUDE OIL FROM ESTABLISHED RESERVES**
Comparison of Forecasts

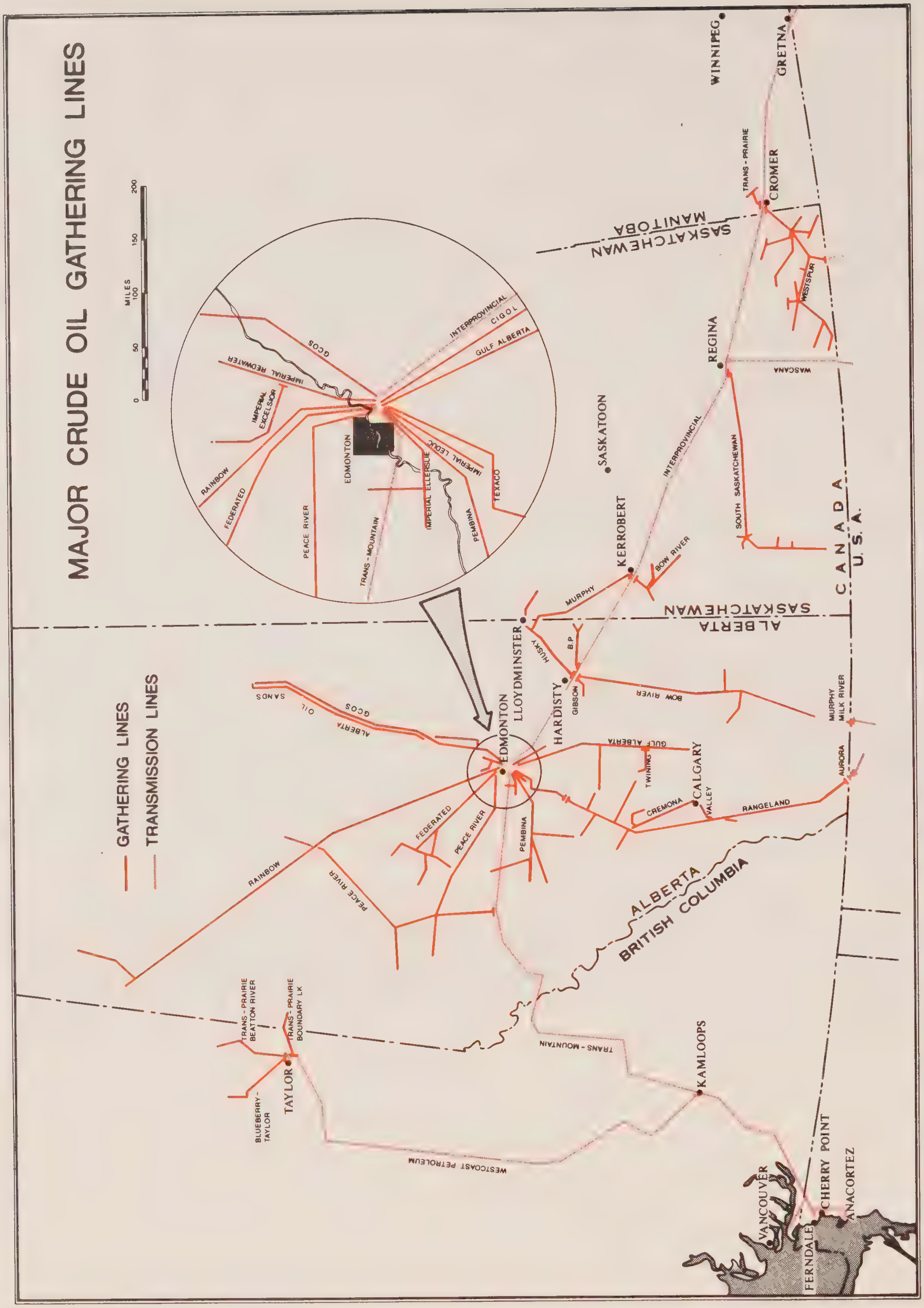
2.2.2 Views of the Board

In making its current estimates of established reserves, the Board has taken into account all reserves evidence received at the inquiry. These estimates are shown in Appendix C on a pool-by-pool basis, and are compared in summary fashion with the submitted estimates in Table 2-1. Following its previous public hearing into Canadian Oil Supply and Requirements, the Board published an estimate of 6474 million stock tank barrels for established remaining recoverable reserves as of 1 January 1976. The Board's current estimate of established remaining recoverable reserves as of 1 January 1978 is 5783 million stock tank barrels. Established remaining recoverable reserves declined by 473 million stock tank barrels in 1976 and 218 million barrels in 1977 following production of 461 million barrels in each of the two years.

The pool-by-pool reserves data in Appendix C are grouped by pipeline systems. The locations of these pipelines are shown on Figure 2-4.

After considering all evidence received in the submissions and in verbal testimony, together with supplemental information supplied after the inquiry, the Board has developed the pool-by-pool potential producibility forecast shown in Appendix D. Summaries of these forecasts are compared with the submitted forecasts in Figures 2-1 through 2-3. The methods and computer models used by the Board to develop potential producibility forecasts have been completely documented in previous Board publications and are not discussed further in this report.

The four factors specified in the beginning of this Chapter are unlikely to have much effect on the determination of reserves currently considered as established. The major effects that they would have on existing reservoirs are considered in Section 2.3 "Additions to Established Reserves in Conventional Areas".



MAJOR CRUDE OIL GATHERING LINES
GATHERING LINES
TRANSMISSION LINES
MILES
0 50 100 150 200
EDMONTON
LLOYDMINSTER
HARDISTY
KERROBERT
SASKATOON
REGINA
CROMER
WINNIPEG
GRETNA
CALGARY
KAMLOOPS
TAYLOR
VANCOUVER
FERNDALE
CHERRY POINT
ANACORTEZ
MANITOBA
SASKATCHEWAN
ALBERTA
BRITISH COLUMBIA
CANADA
U.S.A.
INTERPROVINCIAL
TRANS - MOUNTAIN
WESTCOAST PETROLEUM
TRANS - PRAIRIE
WASCANA
SOUTH SASKATCHEWAN
WESTSPUR
BOW RIVER
MURPHY
HUSKY
B.P.
GIBSON
GULF ALBERTA
TWINING
CREMONA
VALLEY
RANGELAND
AURORA
MURPHY MILK RIVER
PEMBINA
PEACE RIVER
FEDERATED
RAINBOW
GCOS
ALBERTA OIL SANDS
TRANS - PRAIRIE BEATTON RIVER
TRANS - PRAIRIE BOUNDARY LK
BLUEBERRY - TAYLOR
IMPERIAL REDWATER
IMPERIAL EXCELSIOR
IMPERIAL LEDUC
IMPERIAL ELLERSLIE
TEXACO
CIGOL

Figure 2-4

2.3 ADDITIONS TO ESTABLISHED RESERVES IN CONVENTIONAL AREAS

2.3.1 Reserves Additions of Light Crude Oil

2.3.1.1 Views of Submittors

The forecasts of potential producibility from light crude oil reserves additions are compared graphically in Figure 2-5. At the Board's two previous hearings on oil supply and requirements, there appeared to be a consensus that reserves additions would accrue largely from improved recovery methods rather than from new discoveries. That was not the case this time as most companies submitted more balanced estimates regarding the relative supply contributions from these two sources. The change appears to result from increased exploration effort and indicated success, buoyed no doubt by successful exploration results in the West Pembina area of Alberta. The estimates of the potential for recoverable reserves additions from discovery and improved recovery are summarized in Tables 2-2 and 2-3. While comparison of these estimates in aggregate is valid, caution must be exercised in comparing individual components because of differing terminology used by submittors.

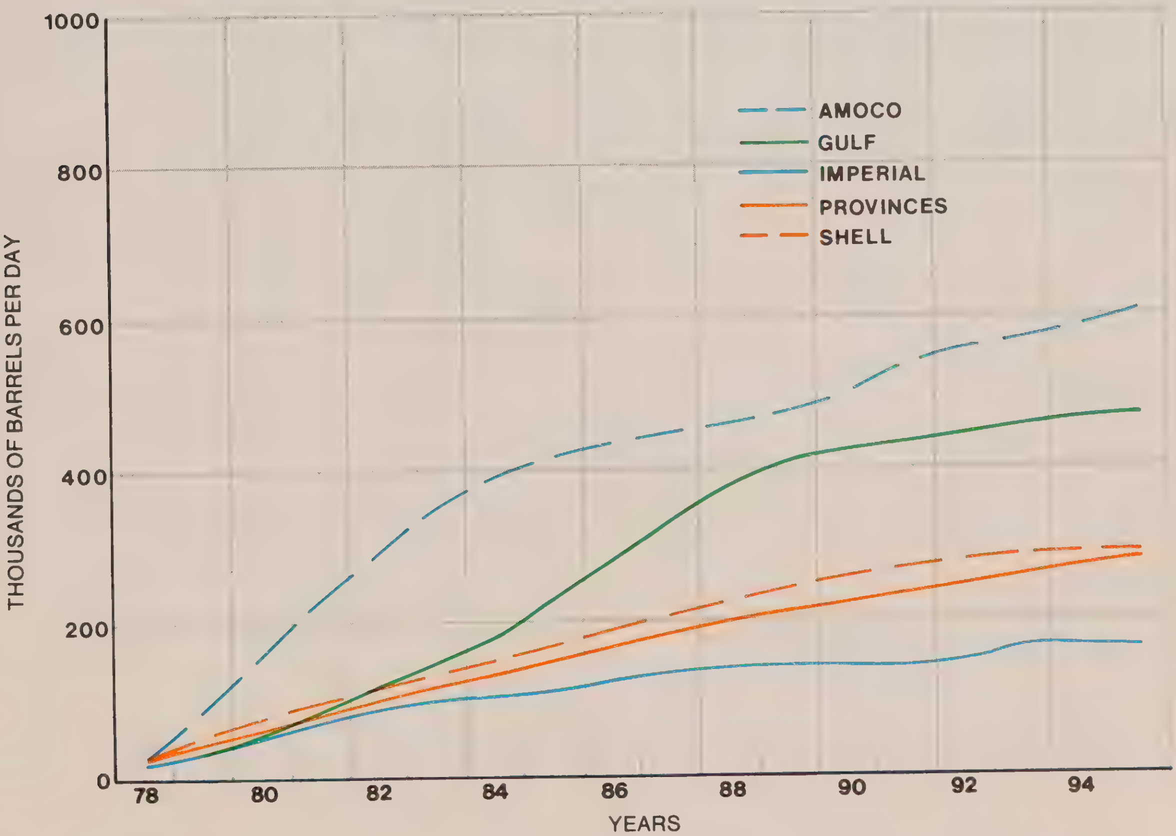


Figure 2-5 **POTENTIAL PRODUCIBILITY FROM RESERVES ADDITIONS OF LIGHT CRUDE OIL**
Comparison of Forecasts

Table 2-2

POTENTIAL FOR RECOVERABLE RESERVES ADDITIONS FROM NEW DISCOVERIES OF LIGHT CRUDE OIL

Comparison of Estimates

(Millions of Barrels)

		Conventional Producing Areas of the Western Canadian Sedimentary Basin		
		Low	Most Likely	High
Amoco		-	- (2300)*	-
Gulf		-	3100 (756)	-
Imperial		1000	1400	2500
Shell		750	1800 (1550)	5000-6000
Provinces	AERCB	-	1200	-
	B.C.	-	65	-
	SASK	-	- (34)	-

	West Pembina Only		
	Low	Most Likely	High
Amoco	-	1500	-
Ashland	-	750	-
Gulf	-	700	-
Imperial	200	320	850
Polar	150	250	500
AERCB	-	500	-

* Numbers in brackets indicate the portion of reserves additions that will likely be discovered by 1995.

Table 2-3

POTENTIAL FOR RECOVERABLE RESERVES ADDITIONS FROM APPRECIATION AND IMPROVED RECOVERY OF LIGHT CRUDE OIL

Comparison of Estimates

(Millions of Barrels)

		Conventional Producing Areas of the Western Canadian Sedimentary Basin			
		Low	Most Likely		High
Amoco:	Appreciation	-	653	(653)*	-
	Tertiary	-	3750	(1700)	-
	Total	-	4403	(2353)	-
Gulf:	Appreciation	-	860	(530)	-
	Enhanced Recovery	-	2800	(507)	-
	Total	-	3660	(1037)	-
Imperial:	Enhanced Recovery	See Table 2-4 and Figure 2-5			
Shell:	Appreciation	313	360	(360)	360
	Supplemental Recovery	-	1000	(532)	2000
	Total	313	1360	(845)	2313
AERCB:	Appreciation	-	400		-
	Exotic Recovery	-	1900		-
	Deferred Abandonment	-	300		-
	Total (Alberta Only)	-	2600		
Sask.:	Total (Saskatchewan Only)	-	38		-

* Numbers in brackets indicate the portion of reserves additions that will likely be discovered by 1995.

CPA

The CPA estimated that the ten discoveries in the West Pembina area involved about 30 million barrels of recoverable reserves as of year end 1977 and that the ultimate potential for the West Pembina play could possibly be in the order of 1 billion barrels or more.

Amoco

Amoco's estimate of reserves potential for the conventional producing areas of the Western Canadian Sedimentary Basin was based on ultimate recoverable reserves approaching 20 billion barrels, of which about 17.5 billion barrels would be light crude oil. The light crude oil reserves additions schedule called for about 1.5 billion barrels to be added over the next ten years and an additional 0.8 billion barrels being added over the ensuing eight years. The 1.5 billion barrels over the next ten years were expected to come almost entirely from West Pembina.

In making its estimates of reserves appreciation, Amoco considered the contributions of four factors; development drilling and pool extensions, improvements in existing recovery methods, installation of waterfloods in small pools, and reserve increases attributed to some infill drilling.

With respect to reserves appreciation, Amoco forecast an annual addition equal to one percent of the remaining reserves in any year.

Amoco estimated the tertiary oil recovery potential for light crude oil reservoirs to be 3.75 billion barrels with about 1.7 billion barrels of this total to be added by the year 1995. Half of the 1.7 billion barrels were forecast to be recoverable by hydrocarbon miscible flooding, which Amoco thinks is an economic method of recovery given today's prices and royalties. The other half would accrue from carbon dioxide or micellar types of floods and would require greater incentives to become economic. Amoco testified that it prefers to install tertiary recovery techniques early in the life of the reservoir as they become much more expensive to install and operate later in the life of the reservoir when water cuts are high.

Ashland

Ashland adopted the NEB's February 1977 forecast of producibility from reserves additions, but it added a component to reflect the West Pembina play. As a rough order of magnitude, Ashland assumed that about 1,160 million barrels of oil in place could be found in the West Pembina area. This could result in an ultimate reserve of about 750 million barrels assuming a recovery factor of 65 percent. These estimates were based on a total of 50 separate discoveries being made in the West Pembina area. Assuming a 15-year constant rate life potential, Ashland stated that rates of production around 137 Mb/d could be reached by 1983.

Ashland believed it reasonable to conclude that the oil reserves and potential assumed above could be at least twice as large if the West Pembina discoveries are indicative of a broader trend.

Chevron Standard

Chevron Standard testified that it simply did not know the ultimate potential of West Pembina. Witnesses stated that estimates of 500 million to 3 billion barrels could be realistic but they were not prepared to sanction any of these estimates at this time. Chevron itself has completed eight wells to date, six of which are tied in and were producing a total of about 5 Mb/d. Three more wells were drilling and two were ready to spud.

Gulf

In terms of new discoveries, Gulf estimated an undiscovered light crude oil potential of 3.1 billion recoverable barrels for Western Canada, of which some 700 million recoverable barrels were expected to accrue from West Pembina.

Gulf submitted a forecast of producibility from reserves additions to existing pools that was divided into two categories: reserves appreciation and enhanced recovery. Producibility additions from enhanced recovery were defined as those involving recovery beyond primary and conventional waterflood recovery mechanisms. Gulf estimated the reserve appreciation potential for light crude oil reservoirs to be 860 million recoverable barrels and the reserves appreciation potential for heavy crude oil reservoirs to be 185 million recoverable barrels. Gulf estimated the potential tertiary recovery additions to light

crude oil reservoirs to be 2.8 billion barrels, most of which were expected from hydrocarbon miscible flooding. Gulf stated that hydrocarbon miscible flooding is economic under today's prices and royalties in Alberta, but that in Saskatchewan improvements in economics are required. Gulf was of the opinion that delaying application of enhanced recovery in certain pools could affect the economics of such projects if wells were abandoned and had to be redrilled.

Imperial

Imperial stated that there were indications that new reserves were being discovered faster than in previous years although little factual data on their ultimate potential was available. Further exploration of related prospects and delineation of the recent discoveries will be required to accurately evaluate the full range of potential. Reports of recent discoveries and evaluation of available data have led Imperial to increase its mean assessment of recoverable remaining undiscovered light crude oil potential to about 1400 million barrels from approximately 1000 million barrels in 1976. This was an actual increase of 650 million barrels as 250 million barrels from new discoveries have been credited in the last two years. While the timing of new discoveries is cyclic, Imperial believed it reasonable to assume that 55 percent of the undiscovered reserve potential would be realized in the next ten years. Imperial's mean assessment of 1400 million barrels was bracketed within a range of about 1 billion barrels to about 2.5 billion barrels. The mean assessment for West Pembina was put at 320 million barrels within a range of 200 million to 850 million barrels. Imperial estimated that about 100 million barrels of the West Pembina potential had already been discovered.

Imperial examined each major producing zone in the Western Canadian Sedimentary Basin to determine what volumes of oil could be recovered by tertiary recovery techniques. A total of 18 billion barrels of oil in place was identified as having tertiary recovery potential by wet combustion, surfactant flooding, and miscible flooding with liquefied petroleum gas or carbon dioxide. Of the total 18 billion barrels, about 3.8 billion barrels were in reservoirs that the Board classifies as heavy crude oil, the remaining 14.2 billion barrels being in light crude oil reservoirs. Results of the study are summarized in Table 2-4.

Table 2-4

POTENTIAL FOR ENHANCED RECOVERY IN THE WESTERN CANADIAN SEDIMENTARY BASIN

Imperial Oil Estimates

(Millions of Barrels)

Producing Zone	Unrecovered Oil-In-Place	Enhanced Recovery Technique	Maximum** Recovery Potential
A. Light*			
Viking	600	Wet Combustion	100
Mannville - High Gravity	900	Surfactant	150
Gilwood	800	Carbon Dioxide	300
Rundle/Pekisko	1500	Carbon Dioxide	150
Swan Hills	3400	Carbon Dioxide	350
Cardium	7000	Surfactant	450
Total Light	14200		1500
B. Heavy*			
Mannville - Low Gravity	2600	Wet Combustion	500
Midale - Medium Gravity	1200	Wet Combustion	250
Total Heavy	3800		750
C. Total Light and Heavy	18000		2250

* Adjusted to NEB definitions
** Crude Price - $30/BBL (1978 $)

Studies were carried out by Imperial for each zone identified as having tertiary recovery potential, and the required economic incentive was determined for applying the appropriate technique. Figure 2-6 shows Imperial's estimate of the impact of price on tertiary recovery potential.

According to the Imperial forecast, enhanced recovery methods will result in about 130 Mb/d of additional producibility of light and heavy crude by 1995.

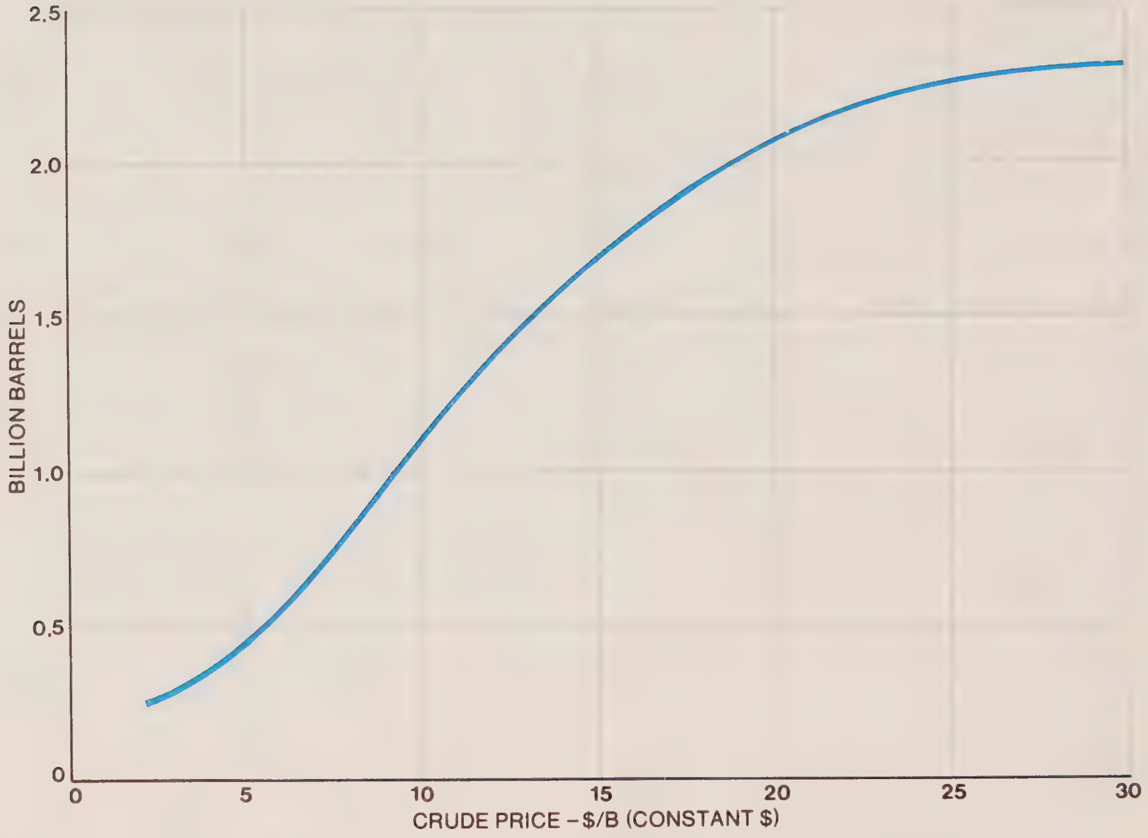


Figure 2-6 **IMPACT OF PRICE ON RECOVERY POTENTIAL Imperial Oil Estimate**

Polar

Polar Gas Limited said that its subjective estimates of West Pembina potential ranged from 150 million barrels to 500 million barrels with the expected value being about 250 million barrels of recoverable oil.

Shell

Shell's estimate of undiscovered light crude oil potential was based on a play-by-play assessment that indicated that the potential for light oil discoveries in the Western Canadian Sedimentary Basin was about 1.8 billion recoverable barrels. Shell estimated that about 1.55 billion barrels of this total will be discovered in the period up to 1995. Its estimate of the most-likely potential of 1.8 billion barrels for new discoveries was within a range of about 3/4 of a billion barrels up to 5 or 6 billion barrels.

To forecast annual levels of light crude oil discoveries, Shell estimated that new field exploratory drilling would increase about 30 percent above the 1976 figure of 440 new field exploratory wells and remain at a plateau for several years before begining to decline slowly. Annual oil discoveries were forecast to average about 160 million recoverable barrels in the early years of the forecast period declining to about 25 million barrels per year in 1995. These estimates were in turn converted to annual additions using the AERCB appreciation curve. A ten to one reserves to production ratio was used to establish a producibility schedule from new discoveries. It was further assumed that about ten percent of this resultant forecast should be credited to heavy oil areas other than Lloydminster.

Shell projected future appreciation of existing reserves using the latest AERCB appreciation curve and the CPA's estimates of ultimate recoverable oil reserves dated back to the year of discovery. These reserves were assumed to go on stream in the year following that in which they were booked, and to produce at a reserves to production ratio identical to that derived from the NEB's 1977 forecast of producibility from established reserves. Shell estimated that about 13 percent of the total could be attributed to heavy crude oil and the remaining 87 percent to light crude oil.

Shell believed that tertiary recovery schemes such as chemical flooding and carbon dioxide miscible flooding would not contribute substantially to light crude oil production until the late 1980's. Also, Shell doubted that hydrocarbon miscible flooding would contribute a large percentage of the production from enhanced recovery in the future. The company favoured carbon dioxide assuming that economic conditions permit.

Shell estimated that in the period up to 1995, supplemental recovery would add about 1.4 billion barrels. Of this total, 532 million barrels would be in light and medium crude oil reservoirs and 897 million barrels in heavy crude oil reservoirs. Including recovery after 1995, Shell estimated that the supplementary recovery potential would be about three billion barrels with about 65 percent or two billion barrels accruing from heavy crude oil reservoirs and about 35 percent or one billion barrels coming from light and medium reservoirs. Shell said that a reasonable range of supplemental recovery estimates for all reservoirs could be anywhere from a high of six billion barrels to a low of practically zero.

Texaco

Texaco Canada estimated the producibility from reserves additions to be 188 Mb/d in 1979, remaining above 200 Mb/d throughout the balance of the forecast period. Texaco did not estimate the ultimate reserves potential for the Western Canadian Sedimentary Basin. Rather, it subjectively adjusted previous CPA submissions. Texaco's forecast assumed rapid development of the new West Pembina reserves, but no other specific source of reserves additions was used to support the producibility forecast.

UFAWU

With regard to light crude oil discoveries, the UFAWU stated its opinion that a comprehensive public energy policy should be based on an additional discovery potential of about five billion barrels. Witnesses testified that this estimate was taken from public statements made by an officer of Petro Canada and that the UFAWU had no additional information to support this estimate. However, it was the opinion of the UFAWU that the West Pembina experience to date would support such an estimate.

The UFAWU also believed that the NEB's estimates for improved recovery potential of 2.07 billion barrels for the base case and a maximum potential of 3.11 billion barrels were unduly conservative projections. However, in response to questioning, witnesses for the UFAWU would not suggest estimates that they believed to be more realistic.

AERCB

The AERCB estimated that about 4.4 billion barrels of light oil in place remain to be discovered in the Province of Alberta. Assuming a 27 percent recovery factor, the recoverable reserves potential from new discoveries would be 1.2 billion barrels. Of the 4.4 billion barrels of oil in place, about 1.9 billion barrels were forecast to be discovered in the Cretaceous, 2 billion in the Devonian, and the remaining 0.5 billion barrels in various less important formations. With respect to the 1.2 billion barrels estimated to be recoverable from new discoveries, West Pembina was expected to contribute about 0.5 billion barrels.

The AERCB estimated that reserves additions to existing pools would come from three sources: appreciation, exotic (tertiary) recovery, and deferred abandonment. Appreciation was forecast to add about 0.4 billion barrels, exotic recovery about 1.9 billion barrels, and deferred abandonment an additional 0.3 billion barrels.

BCEC

The BCEC believed that the Eagle Belloy "F" pool discovery would lead to other similar discoveries in British Columbia, and that the total potential of this play could result in additional finds of 50 million recoverable barrels from this previously-minor oil reservoir. The potential of other plays in the Cretaceous/ Triassic formations was estimated at 15 million recoverable barrels. The production profile, resulting from these reserves additions estimates, rises from about 0.8 Mb/d in 1978 to a maximum of 16 Mb/d in 1986, after which it begins to decline.

The BCEC also estimated that additional potential could come from modifications to existing waterfloods and the installation of tertiary recovery schemes. However, contribution to total supply was expected to be minor until the late 1980's, amounting to less than 1 Mb/d until that time. The development of suitable tertiary recovery schemes could add significant production after that time, perhaps accounting for about 11 Mb/d by 1995.

Saskatchewan

Saskatchewan submitted estimates of the future reserves potential in the province both from additions to existing reservoirs and from new discoveries. Saskatchewan estimated that additions to existing reservoirs would add 254 million recoverable barrels during the forecast period of which 38 million barrels would accrue in reservoirs containing oil designated by the NEB as light. New discoveries were forecast to add 228 million barrels of which 34 million barrels would be light crude oil as designated by the NEB.

Additions to existing reservoirs were expected to result from three sources: future appreciation of existing pools, infill drilling and modifications to existing waterfloods; and the application of tertiary recovery methods. Reserves appreciation constituted over half of the total reserves forecast to be added to existing reservoirs and was expected to result mainly from normal development drilling and waterflooding. Infill drilling and modifications to existing waterfloods were expected to contribute about six percent with pools in the southeastern and southwestern areas of the province having most of the potential. Tertiary recovery was estimated to have the greatest potential. However, Saskatchewan's forecast assumed that tertiary recovery would not make a significant contribution prior to the mid-1980's, and only a conservative contribution from this source was included from that date until 1995.

2.3.1.2 Views of the Board

In assessing evidence presented by submittors, the Board recognizes that no technique exists for predicting, with a high degree of accuracy, the quantities of light crude oil that may be added to established reserves as the result of future discoveries. A substantial element of judgement and speculation is involved. As a result, estimates can be expected to vary considerably, which the evidence in this inquiry clearly demonstrates.

A large part of the variation in estimates presented for Western Canada results from differing opinions as to the potential of the West Pembina play. It should be noted that as this play is in an early stage of development, an assessment of its potential is particularly difficult.

The Board's base-case estimate of the discovery potential for recoverable crude oil in Western Canada is 1.3 billion barrels within a possible range of 0.9 to 2.9 billion barrels. Included in the base-case estimate is 0.5 billion barrels of recoverable oil for West Pembina. Recovery factors used for the Board's assessment include combined primary and secondary recovery for the various plays. The Board's estimates of discovery potential reflect results of independent studies carried out by the Board as well as the evidence submitted at the inquiry. The Board expects that the current level of exploratory drilling will be maintained and that most of this potential will be realized by 1995.

Improved recovery techniques for established reservoirs are expected to add approximately 1 billion barrels to the reserves potential within a range of 300 million to 1.6 billion barrels. Table 2-5 shows the potential for improved recovery of light crude oil by recovery method. These estimates are based on a comprehensive review of the potential for improved recovery for each oil reservoir in Canada conducted by the Board in conjunction with the 1976 hearing. The results of that review appear to the Board to remain valid and they are in line with evidence presented at this inquiry. Initially, most reserves additions in the improved recovery category are expected to come from projects using waterflood, infill drilling, and LPG miscible flooding techniques. However, towards the latter part of the forecast period, the emphasis is expected to shift towards chemical flooding, thermal techniques, and carbon dioxide flooding. Reserves additions from improved recovery are rather small in the earlier part of the forecast period as pilot projects must precede full-scale operations. However, the Board believes that higher crude oil prices and current policies will encourage investment in improved recovery schemes.

The producibility forecast shown in Figure 2-7 is based on the combined reserves additions potential of both new discoveries and improved recovery from established reservoirs with appropriate annual reserves additions and reserve life indices applied to each category.

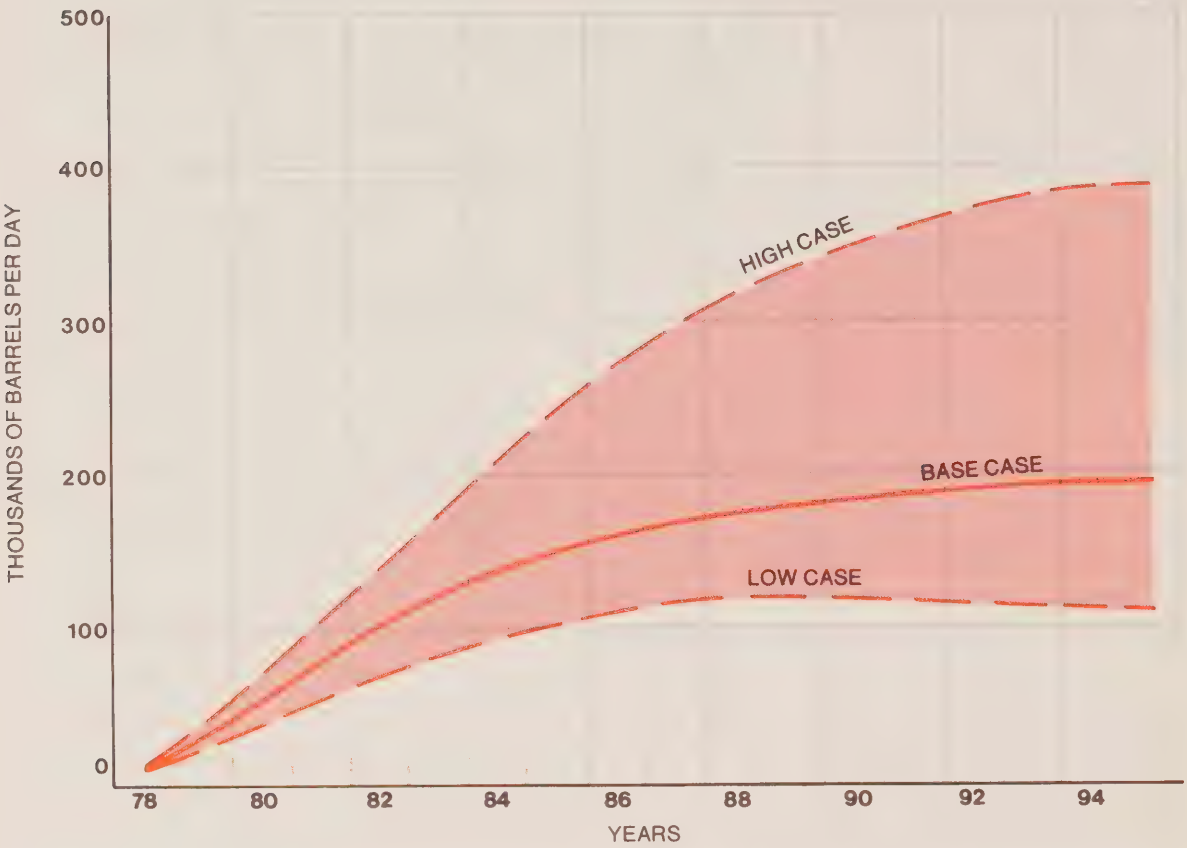


Figure 2-7 **POTENTIAL PRODUCIBILITY FROM RESERVES ADDITIONS OF LIGHT CRUDE OIL**
NEB Forecast

Table 2-5

POTENTIAL FOR RECOVERABLE RESERVES ADDITIONS FROM

IMPROVED RECOVERY OF LIGHT CRUDE OIL

NEB Estimates

(Millions of Barrels)

	Low Case	Base Case	High Case
Chemical Flooding	130	310	470
Infill Drilling	80	130	180
Miscible Flooding	-	370	760
Thermal Techniques	10	30	50
Waterflooding	100	140	170
Total	320	980	1,630

2.3.2 Reserves Additions of Heavy Crude Oil

2.3.2.1 Views of Submittors

The forecasts of potential producibility from heavy reserves additions are compared in Figure 2-8. The reserves potential underlying these forecasts, where available, is presented in Table 2-6.

Gulf

Gulf's estimate of discovery potential for heavy crude oil was approximately 1 billion barrels of recoverable reserves.

Gulf's producibility forecast was based on the assumption that a heavy crude oil upgrading plant would come on stream in 1983. If no plant were built, and if exports were phased out, it stated that this level of producibility would not be developed.

TABLE 2 - 6

POTENTIAL FOR RECOVERABLE RESERVES ADDITIONS OF HEAVY CRUDE OIL

Comparison of Estimates

(Millions of Barrels)

Conventional Producing Areas of the Western Canadian Sedimentary Basin

		Appreciation	Discoveries	Tertiary	Total
Gulf		185 (135)*	1000 (462)	- (55)	- (652)
Imperial		-	-	-	1450
Shell		47	725 (662)	2000 (897)	2772 (1559)
Provinces	AERCB	100	500	500	1200**
	SASK.	-	- (194)	- (216)***	- (410)

Lloydminster Area Only

	Appreciation	Discoveries	Tertiary	Total
Imperial	-	-	-	1200
Shell	-	525 (462)	2000 (897)	2525 (1359)

* Numbers in brackets indicate the portion of the additions that will likely be added by 1995.

** Includes 100 MMSTB from deferred abandonment.

*** Includes all additions to existing reservoirs.

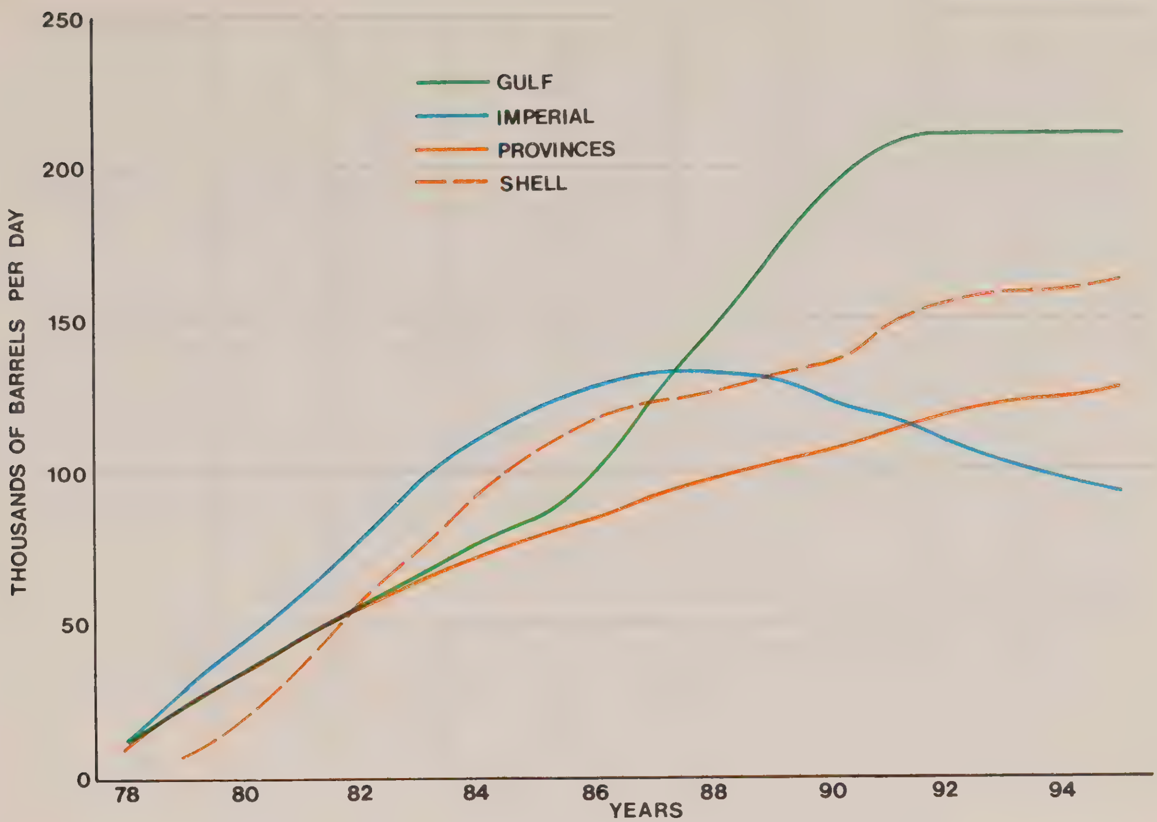


Figure 2-8 **POTENTIAL PRODUCIBILITY FROM RESERVES ADDITIONS OF HEAVY CRUDE OIL**
Comparison of Forecasts

Husky

Husky submitted that its geologists had identified over 1,000 locations on Husky's Lloydminster area lands that could be drilled for primary production with a reasonably high degree of confidence of success. Primary recovery of about 56,000 barrels per well could be expected, a volume which is about six percent of the original oil in place in a 40-acre tract. Husky estimated that a total of about 16 billion barrels of oil in place has been defined in the Mannville sands of the Lloydminster area. This figure has been derived from data obtained from numerous stratagraphic test holes and exploration and development wells, and includes sands with thicknesses greater than five feet of continuous oil saturation.

The primary recovery from Lloydminster reservoirs has normally been from 4 percent to 6 percent of the original oil in place. Waterflooding would, on average, add an incremental 3 percent to 5 percent recovery to the primary expectation, so that present ultimate recovery would range from 7 percent to 11 percent of the original oil in place. Husky estimated that existing Lloydminster fields would have a producibility of about 50 Mb/d in 1979, a level that which would decline to 5 Mb/d by 1995. Additional development of primary and secondary production would increase producibility to 57 Mb/d in 1979, declining to 15 Mb/d by 1995.

Husky believed that a combination cyclic steaming and steam drive process could be developed that would result in significant incremental recoveries from the thicker Lloydminster sands, and that this process would be established on a commercial basis by the mid-1980's. Husky assumed commercial thermal production starting in 1984 would be approximately 5 Mb/d, escalating to 60 Mb/d by 1990. This would result in a total industry production capacity, including primary, secondary, and tertiary recovery schemes, that could reach much more than 100 Mb/d by the early 1990's.

Husky estimated that incremental recoveries resulting from steam application would range from 15 percent to 30 percent for the thickest portions of Lloydminster reservoirs. Husky had identified areas totalling more than 100,000 acres where continuous sand pays were greater than 15 feet and ranged up to 50 feet. The areas identified were all on Husky's controlled acreage and contained in excess of three billion barrels of oil in place.

With regard to commercial steam drive projects, Husky said that one could anticipate that producibility would vary from 5 Mb/d to 10 Mb/d per section. Cyclic and steam drive initial production response should range from 60 to more than 100 barrels of oil per day per well for these projects.

Imperial

Imperial conducted a detailed assessment of the reserves potential of existing pools and undeveloped reserves assuming the use of various recovery methods including enhanced recovery. Available data from about 5000 wells throughout the general Lloydminster area were examined to arrive at an oil in place estimate of 23.1 billion barrels (see Table 2-7). Imperial believed that current technology will not permit economic recovery from reservoirs containing oil with an API gravity of less than 12 degrees or from those reservoirs completely underlain by water, categories that represent 11.3 billion barrels of the total oil in place potential. Accordingly, the determination of recoverable reserves and producibility was based on the remaining 11.8 billion barrels of oil in place.

Table 2-7

POTENTIAL FOR RESERVES FROM THE LLOYDMINSTER AREA

Imperial Oil Estimate

(Billions of Barrels)

Existing Technology	Oil in Place	Percent Recovery	Ultimate Recoverable Reserves
Existing Pools	4.9	14.0	0.7
Undeveloped Pools (12° API)	6.9	11.0	0.8
Total	11.8	12.5	1.5
Requiring New Technology			
Undeveloped (12° API)	5.0		
Oil Underlain by Water	6.3		
Total	11.3		
Total Oil In Place	23.1		

Imperial's estimate of the oil in place outside the existing pools in the Lloydminster area that could be developed with existing technology was 6.9 billion barrels. Imperial's witnesses testified that this estimate is probably within plus or minus ten percent as most of the pools included have been penetrated by at least one well. Imperial assumed that, generally, any sand body that was less than five feet thick was not economic to develop. However, it did not rigidly adhere to a five-foot net oil pay cut-off. Imperial further estimated that about 60 Mb/d of new producibility could be developed in the Lloydminster area with an annual drilling rate of about 500 wells provided the pools were placed immediately on waterflood. Imperial was not optimistic that a 100 Mb/d upgrading plant located in the Lloydminster area could attract sufficient feedstock and it was certain there was no hope for a potential of 300 Mb/d of upgraded crude oil.

For areas other than Lloydminster, Imperial estimated the potential for heavy oil reserves additions to be about 250 million barrels of recoverable crude oil.

In southeastern Alberta, additions from new discoveries, primarily in the Suffield area, and enhanced recovery were expected to result in additional producibility of about 18 Mb/d by 1985.

McDaniel

McDaniel Consultants submitted an assessment of the conventional heavy oil potential in the area of Alberta extending from the Taber region in the south to the Lloydminster area in the north. The volumes of proved conventional heavy oil in place were estimated to be 4.1 billion barrels at the end of 1977, compared with 2.7 billion barrels at the end of 1973. McDaniel extrapolated this growth of oil in place using annual growth rates commencing with 9 percent in 1978, decreasing to 7 percent by 1980, 5 percent by 1985, and 3 percent by 1995. The resulting oil in place estimate for the year 1995 was nine billion barrels. Recoverable reserves of about one billion barrels were calculated using an assumed recovery factor of 11.5 percent. McDaniel concluded that only 6.2 percent of the estimated resource base in the Eastern Alberta heavy oil area would be required to support production levels of up to 160 Mb/d throughout the forecast period.

Murphy

Murphy stated that it agreed with the analysis as put forth by Imperial indicating oil in place of roughly 23 billion barrels for the Lloydminster area. The distribution of oil by gravity and reservoir configuration as set out by Imperial also conformed to the Murphy analysis. However, Murphy believed that almost two-thirds of the oil in place of more than 20 billion barrels was unavailable as a primary or secondary contributor to reserves.

Murphy said that it would be hesitant to invest in a 100 Mb/d upgrading plant at Lloydminster because of a possible shortage of feedstocks. The preferred location would be on the IPL pipeline at Kerrobert, where the plant would have access to more of Canada's heavy crude oil. With regard to the economics of upgrading, studies made by Murphy indicated that the capital cost per barrel in a 50 Mb/d plant was likely to range between 15 percent and 25 percent greater than in a 100 Mb/d plant.

Murphy estimated that the maximum obtainable producibility for the Lloydminster area by the year 1985 would be about 100 Mb/d and that this would have to come almost entirely from primary and waterflood production. Murphy assumed that the industry could carry on a drilling program of up to 1,000 wells a year in the Lloydminster area. Less than 20 rigs would be required and these would likely be available from existing inventory, or with minor additions to inventory. New wells could be expected to have an average productivity in the range of 25 to 35 barrels per day and a producibility decline of about 15 percent per year.

With regard to thermal recovery techniques, Murphy believed that steam recovery would not be justifiable for the thinner Lloydminster sands. Murphy continued to hold the view that combustion has more potential than steam for Lloydminster-type reservoirs that have 20 feet or less of net pay. Murphy believed that added economic incentive was required to justify thermal recovery in the Lloydminster area. Currently, heavy oil is attracting the lowest price and incurring the highest cost of production. Lifting costs for tertiary recovery in Lloydminster were estimated to be in the range of $5.00 to $6.00 per barrel in fairly large projects. This compared with lifting costs for primary and waterflood oils of about $2.50 to $3.00 per barrel. Murphy was concerned that a widening of the price differential between light and heavy crudes, in order to make upgrading economic, would discourage thermal recovery experimentation.

Shell

Shell assumed that drilling in the Lloydminster area would increase by about 50 percent by the early 1980's from the 1976 level of 430 wells, then decline to about 300 wells per year in 1995. Recoverable reserves additions per well, which averaged about 47,000 barrels between 1967 and 1971 and 53,000 barrels between 1972 and 1976, were assumed to average 50,000 barrels per well until 1983 and to slowly decline thereafter to 35,000 barrels per well by 1995. On this basis, reserve additions were projected to be about 30 million barrels per year for several years declining to 11 million barrels per year by 1995. A certain amount of adjusting was done with the objective of utilizing the approximately 0.5 billion barrels of undiscovered and undeveloped reserves, essentially over a 20-year period. This schedule was converted to production using a reserves to production ratio of seven to one.

Shell estimated that there was a potential for heavy crude oil discoveries of about 725 million barrels of recoverable crude oil. Of this remaining undiscovered potential, about 525 million barrels were expected to be discovered in the Lloydminster area. This latter estimate was obtained by choosing the EMR estimate of 12 billion barrels of oil in place for the Lloydminster area, and subtracting 5 billion barrels that represent oil in place already discovered. This leaves a potential for undiscovered oil in place in the order of 7 billion barrels.

AERCB

The AERCB estimated that about 4.6 billion barrels of oil in place remain to be discovered in Alberta. Nearly all of this total, about 4.5 billion barrels, was forecast to be discovered in the Cretaceous. At a recovery factor of 11 percent, this would represent potential recoverable oil of about 0.5 billion barrels from heavy oil discoveries.

As in the case for light crude oil, the AERCB estimated that reserves additions to existing heavy crude oil reservoirs would come from three categories: appreciation (about 0.1 billion barrels), exotic recovery (0.5 billion barrels), and deferred abandonment (0.1 billion barrels). To translate a schedule of annual reserves additions into producibility, an initial peak productivity of 250 b/d per million barrels of primary reserves was used. Heavy oil pools were assumed to decline hyperbolically with a decline of 12 percent per year and an exponent of 0.5. These decline rates were based on a review of existing pools.

Saskatchewan

Saskatchewan estimated that reserves additions in the Province during the forecast period would accrue from two sources: additions to existing reservoirs, and new discoveries. Additions to existing reservoirs were forecast to add 254 million barrels, of which 216 million would be in reservoirs containing oil designated by the NEB as heavy. New discovery additions during the forecast period were estimated to be 228 million barrels of which 194 million barrels would accrue from reservoirs containing oil designated by the NEB as heavy. Of the totals for heavy crude oil, the Lloydminster area was forecast to provide 113 million barrels through additions to existing reservoirs and 132 million barrels through new discoveries.

Saskatchewan estimated that the probable heavy oil in place outside of existing pool boundaries in the Lloydminster area of Saskatchewan is 7.4 billion barrels.

Saskatchewan believed that if an upgrading facility were not built, the Lloydminster area in Saskatchewan could achieve and sustain a level of producibility of about 35 Mb/d. In the year 1985, 11 Mb/d would accrue from established reserves and 24 Mb/d from future reserves additions. Saskatchewan estimated that if an upgrading facility were built, the 24 Mb/d of producibility from future reserves additions could be doubled without much difficulty. Sustaining such a level of producibility would depend largely upon the success of tertiary recovery schemes in the Lloydminster area.

2.3.2.2 Views of the Board

Because of its importance relative to other heavy crude oil deposits, the Board has considered the Lloydminster area separately. Based on the evidence and its own detailed study, the Board has increased its estimate of the reserves additions potential of the Lloydminster area and the expected rate of development of these resources. Drilling in the Lloydminster area is expected to increase by about 50 percent in the next five years as a result of increased interest in this area by producers and by governments.

Table 2-8

POTENTIAL FOR RECOVERABLE RESERVES ADDITIONS
OF HEAVY CRUDE OIL

NEB Estimates

(Millions of Barrels)

LLOYDMINSTER

	Low Case	Base Case	High Case
Conventional Recovery - Undeveloped Pools	160	420	730
- New Discoveries	120	300	520
Thermal Recovery	580	1200	2440
Total	860	1920	3690

OTHER HEAVY CRUDES

	Low Case	Base Case	High Case
New Discoveries	80	100	140
Improved Recovery	235	550	820
Total	315	650	960

Table 2-8 provides a breakdown of the Board's analysis of heavy crude oil reserves additions. The analysis for the Lloydminster area is based on an ultimate potential of about 10, 15, and 18 billion barrels of oil in place for the low, base, and high cases respectively. Of this, approximately 4.5 billion barrels of oil in place, expected to yield 406 million barrels of recoverable oil, are currently on production using mainly conventional recovery methods. Of the remaining potential, about two-thirds is located in known but undeveloped pools and the rest has to come from new discoveries. The Board's estimate of the oil in place represents only oil that is amenable to economic recovery. The total oil in place potential, including the potential of very thin sands, very lean sands, or sands with a combination of factors that prohibit economic recovery, may be double this amount. The Board has not changed its estimate of the new discovery potential for other heavy crude oil, but it has increased the rate at which this

potential will be realized. Table 2-9 provides a breakdown by method of the Board's estimate of improved recovery potential for other heavy crude oil. The producibility forecasts for Lloydminster and other heavy crudes have been combined and the resulting potential producibility from heavy crude oil reserves additions is shown in Figure 2-9. Realization of this forecast is contingent upon continued full marketability of the various heavy crudes.

Profitability of investments in heavy crude oil development is heavily dependent upon availability of markets for all volumes produced. Assured markets are even more important to support higher relative costs of recovering oil through thermal recovery techniques. In January 1977 the Board began separate licensing of heavy crude oil which allowed production capacity to be fully utilized. This

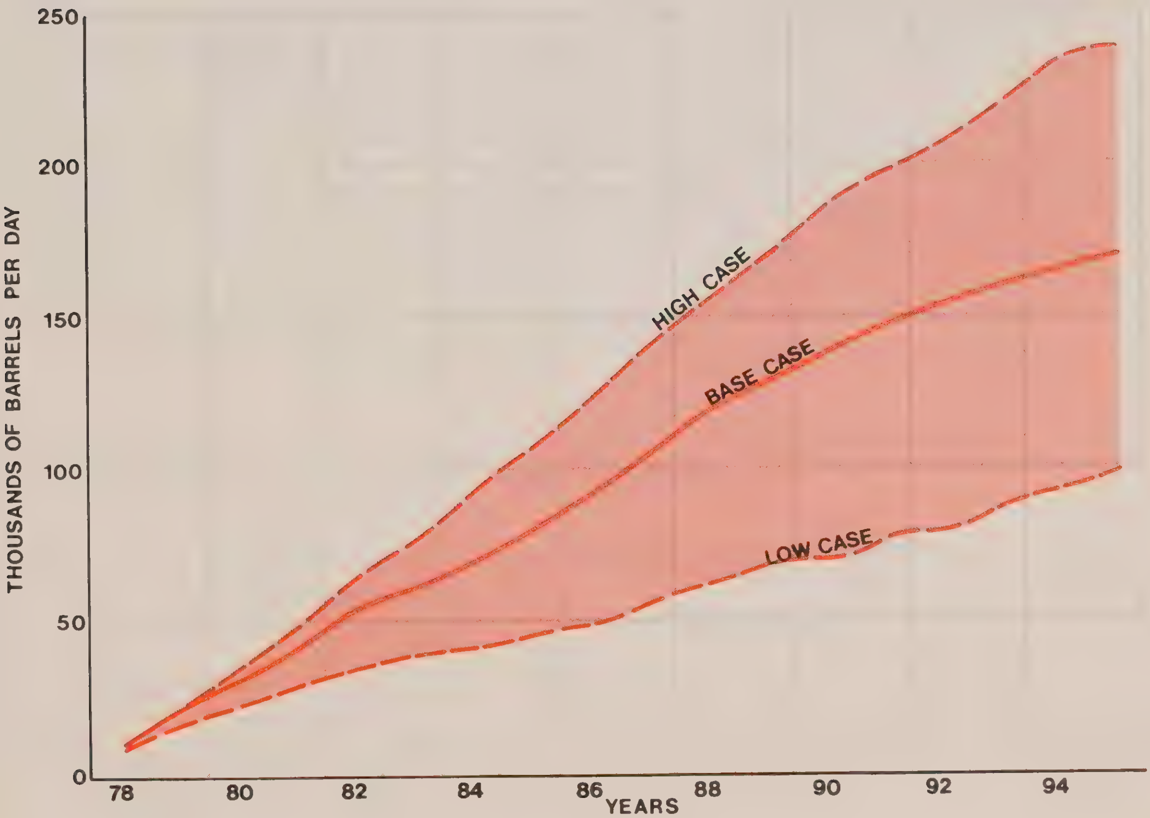


Figure 2-9 **POTENTIAL PRODUCIBILITY FROM RESERVES ADDITIONS OF HEAVY CRUDE OIL**
NEB Forecast

Table 2-9

POTENTIAL FOR RECOVERABLE RESERVES ADDITIONS FROM IMPROVED RECOVERY OF HEAVY CRUDE OIL EXCLUDING LLOYDMINSTER

NEB Estimate

(Millions of Barrels)

	Low Case	Base Case	High Case
. Chemical Flooding	5	25	45
. Infill Drilling	25	35	45
. Miscible Flooding	-	110	280
. Thermal Techniques	110	245	310
. Waterflood	95	135	140
. Total	235	550	820

circumstance, coupled with higher oil prices and the prospect that markets will be assured possibly through heavy oil upgrading, has caused greater optimism over the outlook for heavy crude oil development. The market outlook for heavy crude oil and the implications of an upgrading facility are further discussed in Chapters 6 and 8.

2.4 PENTANES PLUS

2.4.1 Views of Submittors

The views of submittors regarding this class of reserves were detailed principally in forecasts for individual natural gas processing plants in the form requested by the Board in its Outline for Submissions, which is included as Appendix B. In addition, Amoco, Gulf, Imperial, Shell, and Texaco submitted forecasts of production from established reserves and from reserves additions for Canada as a whole. The AERCB provided forecasts of pentanes plus production from proved remaining recoverable reserves and from reserves growth

for Alberta. The CPA provided a forecast of pentanes plus production from established reserves for all of Canada. The forecasts of pentanes plus production submitted to the Board are shown in Figure 2-10. The forecasts shown include pentanes plus production from established reserves together with production from forecast reserves additions.

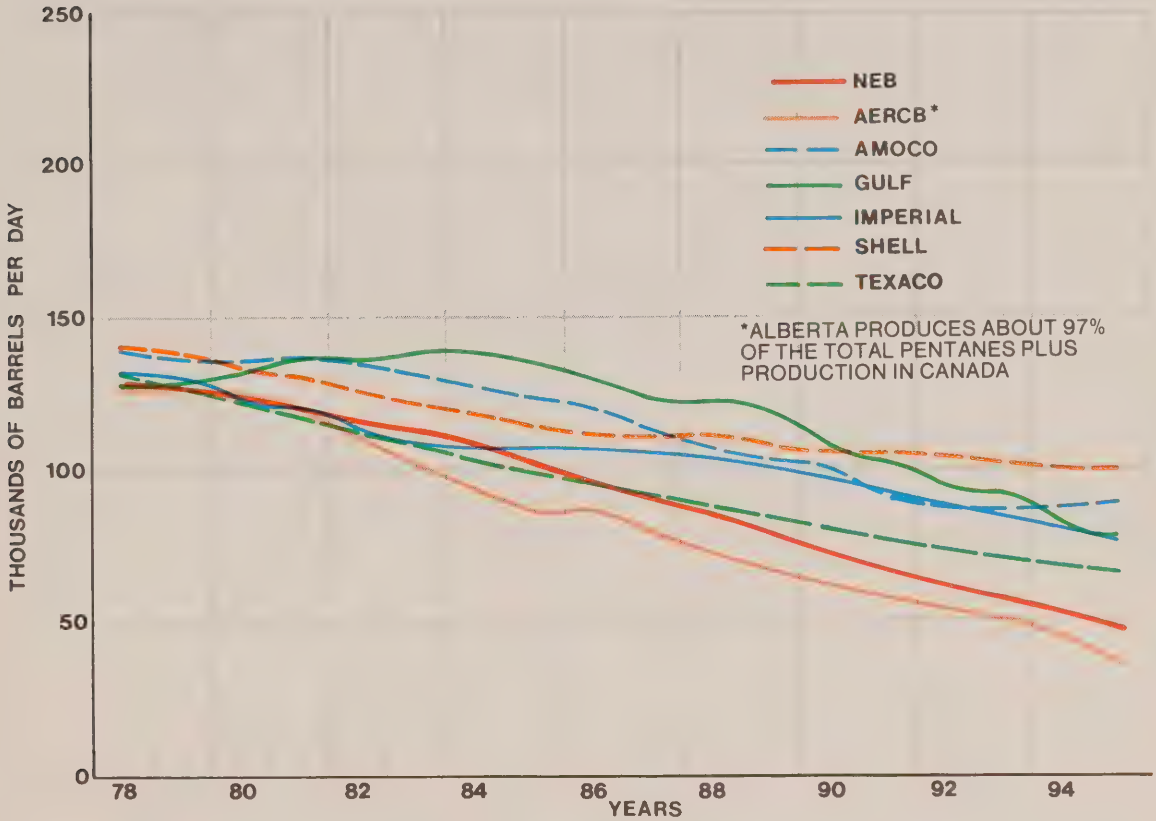


Figure 2-10 **PRODUCTION OF PENTANES PLUS Comparison of Forecasts**

CPA

The CPA submitted that its forecast of pentanes plus production was based on forecasts for 46 plants supplied by 20 plant operators representing 87 percent of the current pentanes plus production in Canada. Production from the remaining plants was estimated on the basis of their current share of total Canadian production. It also submitted that the 1978 level of pentanes plus production compares closely with the CPA 1976 estimate. However, the current forecast submitted indicated higher levels of pentanes plus production in future years than estimated in 1976, the difference reaching a high of 17 Mb/d for the years 1983 and 1984.

Amoco

Amoco's forecast of pentanes plus production from existing reserves was stated to be based on the CPA forecast. New additions to pentanes plus production were based on the National Energy Board's June 1977 forecast of natural gas demand. An initial pentanes plus yield of 15 barrels per million cubic feet of marketable gas was used declining to 10 barrels per million cubic feet in ten years and remaining constant thereafter for associated and non-associated gas reserve additions, and for expected pentanes plus production from solution gas of new oil discoveries and tertiary oil production.

Gulf

Gulf submitted that its forecast of pentanes plus production was based on a revised natural gas production forecast and a revised natural gas richness forecast. It was submitted that in the last few years substantial volumes of relatively dry shallow gas have come on stream and production from richer pools has been cut back due to the current over-supply situation. As a result, the production of pentanes plus has been reduced. However, natural gas demand was forecast to increase as well as production from richer pools. This would result in increased pentanes plus production for several years.

Imperial

Imperial submitted that its forecast of pentanes plus production was derived from the liquids yields from gas produced in association with oil and non-associated gas from gas processing plants. The associated gas volumes were based on Imperial's oil producibility forecasts.

Shell

Shell stated that it had participated in preparing and had adopted as its own the forecast of pentanes plus submitted by CPA. Shell also submitted a forecast of pentanes plus production from appreciation of existing reserves and from new discoveries.

The forecast of pentanes plus production from appreciation of existing reserves was made using the AERCB's appreciation curve for gas and the CPA's estimate of proved reserves by discovery year. The schedule of additions to gas reserves created was delayed one year and then projected to be produced at five percent of initial reserves volume annually for the first eight years. Following the flat life period production was assumed to decline at ten percent per year.

For pentanes plus production from new discoveries, Shell submitted that the forecast was based on an estimate that about 36 trillion cubic feet of natural gas remain to be discovered in the producing regions. Initially, the annual discovery volumes average about 3 Tcf per year declining to about 2 Tcf per year by 1985 and about 0.4 Tcf in 1995. Of this volume, about 8 Tcf was estimated to be shallow dry gas and was ignored in the pentanes plus analysis. Shell estimated the average pentanes plus content of producing regions non-shallow gas to be 21.6 Mbbl per Bcf of gas. This ratio was assumed to hold for future discoveries. Shell submitted that on average in the initial year of production, the pentanes plus to gas production ratio is 145 percent of the average ratio taken over the producing life of the pool. Recovery efficiency declines steadily until by the 14th year it equals the over-life ratio, following which the recovery ratio declines below the over-life ratio. Shell also emphasized that the forecast of pentanes plus production from new discoveries assumes sufficient price and work incentives to ensure a high level of exploration activity over the next several years.

Texaco

Although Texaco did not provide information on the methodology used in arriving at a forecast of pentanes plus production, it submitted that it had used, with modifications, the CPA forecasts of pentanes plus production as the basis for traditional southern basin areas.

AERCB

The AERCB's forecast of pentanes plus production from remaining recoverable gas reserves was based on a study done for its February 1977 Report 77-C. This study had been updated to correspond with its most recent estimate of the expected gas production in Alberta. The forecast of expected gas production was based on an ultimate reserve of 110 Tcf and was related to a forecast of gas requirements for Alberta and Canada, having regard for Alberta's current 30-year protection policy.

With regard to pentanes plus from remaining recoverable gas reserves, the AERCB stated that the forecast took into consideration gas deliverability schedules submitted by owners and by gas purchasers operating in Alberta, the productive capacity of existing reserves, gas processing facilities in existence or approved, plant operating histories, and owners' submissions and progress reports for gas cycling schemes. In constructing the forecast of pentanes plus production using the expected gas production forecast, pentanes plus to gas production ratios were determined from the pentanes plus production estimated from proved reserves as shown in AERCB Report 77-C. The ratios used decreased from 19.4 barrels per million cubic feet in 1978 to 11 barrels per million cubic feet in 1995. These ratios were applied to the current estimate of gas production from proved reserves to determine the proved pentanes plus production forecast.

The pentanes plus production from reserves growth was based on the AERCB's forecast of the growth pattern in proved initial reserves of marketable gas. The AERCB used a pentanes plus to gas production ratio of 15 barrels per million cubic feet in 1979 decreasing to 10 barrels per million cubic feet near the end of the forecast period.

The AERCB said that it believed that the ultimate gas reserves in the Province may possibly be higher than 110 Tcf. If this should be the case, the AERCB said that the forecast of pentanes plus production submitted would be somewhat higher. It also submitted that a variance in the liquid content of new gas discoveries or changes in gas production levels as a result of new removal permits or changes in the existing Alberta protection policy could alter the production levels from those shown in their submission.

2.4.2 Views of the Board

As it did for its February 1977 report, the Board has employed a computer model in arriving at its pentanes plus production forecast. The model accounts for natural gas production on a pool-by-pool basis. The pools are grouped according to the gas plant in which the gas is processed. Changes in the yield of pentanes plus due to depletion of the reservoir, changes in the volumes of cycled gas, as well as the recovery efficiency of pentanes plus in each processing plant are considered in the model.

In the light of the evidence received, the original list of plants has been adjusted. Reference to several plants was deleted and others added to give a final list of 82 plants or groups of plants (by field or area). These plants or groups of plants studied in detail accounted for nearly all of the Canadian production of pentanes plus in 1977. A summary of the pentanes plus production forecast is shown in Appendix E.

In constructing a forecast of pentanes plus production from annual reserves additions, a forecast of natural gas deliverability from reserves additions was combined with a forecast of pentanes plus yields from these additions. Initial yields, estimated to be 15 barrels per million cubic feet of marketable gas, decline to 10 barrels per million cubic feet over a period of ten years and remain constant at that value for the remainder of the forecast period. This portion of the pentanes plus forecast also includes pentanes plus production from gas plants currently under construction.

The Board's forecast of pentanes plus production from established reserves and reserves additions is shown in Figure 2-10. As can be seen from the graph, the Board's current forecast is in close agreement with several of the submittors in the early years of the forecast, but is significantly lower than most of the industry submittors in the latter years of the forecast period. The Board's forecast of pentanes plus production is somewhat higher than the forecast published in its February 1977 report, averaging about 15 Mb/d higher during the period 1983 to 1989. This increase is due in part to recent developments in oil and gas discoveries in Western Canada; the coming on stream of new straddle plants; higher anticipated pentanes plus production from cycling gas pools at the time of commencement of

blowdown; and the blowdown of gas caps associated with oil pools. The increase also reflects the deferral of some gas production because of the reduction of crude oil production and the consequent carry-forward effect on oil producibility.

2.5 OIL SANDS DEPOSITS

2.5.1 Views of Submittors

Forecasts of oil sands producibility were received from nine submittors. These forecasts are compared graphically in Figure 2-11. There was unanimity among the submittors that the identity of the next three commercial projects would be a Syncrude expansion, Imperial's Cold Lake in situ project, and Shell's Athabasca mining project, although not necessarily in that chronological order. The forecasts of most likely start-up dates for these projects are compared in Table 2-10.

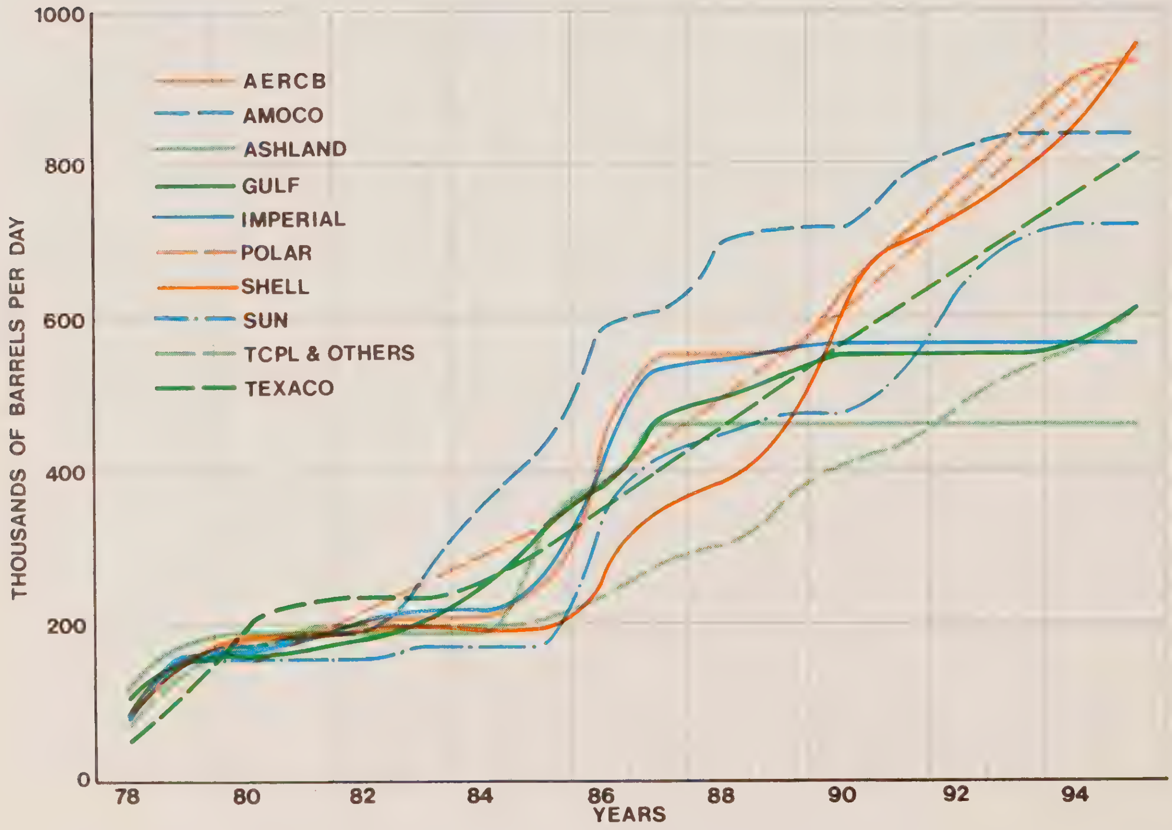


Figure 2-11 **POTENTIAL PRODUCIBILITY FROM OIL SANDS Comparison of Forecasts**

TABLE 2-10

START-UP DATES OF MAJOR OIL SANDS PROJECTS

Comparison of Forecasts

Submittor	First Full Year of Production		
	Syncrude Expansion	Cold Lake In Situ	Third Athabasca Mining
Amoco	1985	1986	1984
Ashland	-	1987	1985
Gulf	1984	1987	1985
Imperial	1985	1986	1986
Polar	-	1985	1987
Shell	-	1987	1986
Sun	-	1986	1986
TCPL, Northern and Central, and Consumers'	-	1986	1989
Texaco	-	1986	1985
AERCB	1985	1986	1986

CPA

The CPA did not submit a detailed oil sands producibility forecast, but did say that aggressive development action certainly must be encouraged if production of synthetic crude oil is to increase to 600 Mb/d by the late 1980's. This rate is based on expanded GCOS and Syncrude plants, an additional mining project, an in situ plant, and a heavy oil plant. Witnesses testified that in the opinion of the CPA, it was questionable at the present pace whether this level of production would be attained.

Amoco

Amoco estimated that in addition to capacity increases planned for the GCOS and Syncrude plants in 1981 and 1985 respectively, it appears that there will be a third oil sands mining project ready for 1984, an in situ project in 1986, and either a fourth oil sands mining project or a second in situ project in 1991. Amoco submitted that in order to justify the investment necessary for such plants, further improvements are necessary in the existing royalty and tax regime, and assurances must be obtained that synthetic crude will be sold at international prices.

Ashland

Ashland expected the oil sands industry by 1980 to consist of an expanded GCOS plant producing 60 Mb/d, an experimental 5 Mb/d Cold Lake project, and the 125 Mb/d Syncrude plant. A third mining operation was forecast to be on stream by 1985 at 125 Mb/d. Ashland assumed that the recently announced Imperial Oil Cold Lake in situ project would come fully on stream by 1987. Ashland did not include a Syncrude expansion or any additional oil sands development projects, as the approach taken was to include only the active commercial ventures publicly proposed at this time.

Fisher's

F.T. Fisher's Sons Ltd. presented a novel technique for extracting oil from oil sands and heavy oil reservoirs. The technique entails the electric induction heating of fossil fuels in situ. Up to the present time, experimental work has been conducted at room temperature and atmospheric pressure to measure the dielectric dissipation constants of several ranks of coal and of oil sand. Future work proposed included a series of surface and in situ heating trials necessary to establish the validity of the technical assumptions made. Fisher's submitted that details of its theory have been made available to a wide variety of companies and agencies for assessment.

Gulf

Gulf estimated that production from the GCOS plant would increase from current levels of 45 Mb/d to 60 Mb/d by 1982 in response to receiving world prices at the higher production level. This would primarily be the result of "debottlenecking" the current plant rather than an expansion. Syncrude was assumed to begin production in 1978 and build up to its design production of 125 Mb/d by 1983. An expansion of the Syncrude plant was assumed to go on stream in 1984 with a design capacity increment of 50 Mb/d. Shell's Athabasca mining plant was assumed to commence production in 1985, and Imperial's Cold Lake in situ project was assumed to commence production in 1987.

Gulf estimated that a minimum of about seven years is required from the time of application until the completion of an oil sands plant. Regarding the optimum size of mining projects, witnesses testified that this is a function of the mine and can be assessed properly only after the mine is in operation.

HBOG

HBOG described its oil sands scenarios, which called for annual producibility increments of 100 Mb/d after the mid-1980's as a maximum possible estimate. Witnesses said that such a development rate was achievable but they did not expect that it could be much higher than this.

Witnesses also said that trying to build an in situ project and a mining project at the same time would not be as difficult as trying to construct two mining projects concurrently.

HBOG said that no firm commitments have been made to proceed with those multi-billion dollar projects and attributed this to the lack of satisfactory risk-reward ratios. The company believes that synthetic crude oil development needs world oil prices, guaranteed markets, and also that governments must be prepared to accept a lower portion of revenues from these developments than they receive from conventional producing operations.

Imperial

Imperial assumed that GCOS will increase its production capacity in 1981 to 65 Mb/d from the current rate of about 50 Mb/d. Syncrude was scheduled to commence production in 1978 and to increase to the permit level of 130 Mb/d, including butanes, by 1983. An expansion of the Syncrude facility was assumed to come on stream in 1985, bringing its capacity to about 200 Mb/d by 1990.

Two additional oil sands projects, Imperial's Cold Lake in situ project and Shell's Athabasca mining project were both assumed to be mechanically complete in late 1985 with production to begin in 1986. The size of the Imperial project was estimated to be 145 Mb/d and that of the Shell project to be 125 Mb/d. Imperial said that as the time of implementation of these two projects draws closer, it is possible that the production schedule shown for the mid-1980's will be smoothed in some way by a modification in the pace or size of one or more of the projects. Although the actual level of production may vary from that forecast for the individual years 1986 through 1989, the 1990 capacity of 535 Mb/d could still be achieved.

With regard to a Syncrude expansion, Imperial estimated that a decision on whether to carry on detailed engineering would be made about one year from now, that this process design work would take until the end of 1980 to complete, and that it would take until early 1985 to have the project on stream. Imperial estimated that the most-likely size of the expanded Syncrude facility would be 195 Mb/d to 200 Mb/d.

With regard to the Cold Lake in situ project, Imperial stated that it would not change its construction timing as a result of any announcement by Shell to proceed with a mining plant. If Cold Lake were expanded, it would take about six years from the point of decision until the expanded facility was in operation.

Imperial stated that supplies of synthetic oil could fall below projected levels if fiscal terms and conditions for new increments of supply proved to be inadequate to attract the required investment. Royalty arrangements accorded Syncrude would not, in Imperial's opinion, be adequate for further projects, including its own Cold Lake project. Imperial testified that the income tax changes in the April 1978 federal budget were a significant improvement but that it would like to see additional changes.

Oleophilic Sieve

The Oleophilic Sieve Society of Alberta submitted details of a new process for separating bitumen from mined oil sands. The process, which the Society believes has significant promise, is being developed to replace the hot water extraction process used at GCOS and Syncrude. Water and sand pass through the sieve, but bitumen is attracted to the surface and recovered. The principal advantages of the process were suggested to be lower separation temperatures, which result in reduced energy requirements, reduced water requirements, and reduced environmental hazards from tailings ponds.

The process has been under laboratory development for about two years now, and attempts are being made to commence pilot testing.

Polar

In its forecast of oil sands production, Polar made an allowance for the production of about 375 Mb/d from three Cold Lake projects by 1995, and the production of about 575 Mb/d of synthetic crude oil by 1995 from the Athabasca oil sands. Polar based its forecast of progressive development upon continuing steady exploitation of the oil sands, on the assumption that oil sands mining plants and in situ plants would be built or expanded every five years commencing in 1987 and 1989 respectively. Presumably, as the work force became available from one plant it would move on to the next. A similar rationale was used for the Cold Lake projects where the construction of plants in 1985, 1990, and 1995 was predicted. Polar submitted that such acceleration would require major changes in the fiscal terms governing these operations, either in the pricing mechanism or the tax treatment; e.g., tax write-offs of approximately 150 to 200 percent of the capital involved; a long-term royalty holiday; and possibly marginal pricing. In the short term, major limitations were seen to be the availability of manpower, infrastructure, and materials. Polar believed that these limitations could and would be overcome if these oil developments were to become economically feasible.

Shell

Shell said that a target of one million barrels a day of oil sands and heavy oil production is not achievable by 1990, mainly because of the sheer magnitude of the effort involved and the slow pace of progress towards project implementation. In its view, even with a high level of encouragement, such a volume is unlikely to be reached before 1995.

Shell listed three particular constraints that must be alleviated before there is a practicable possibility of achieving even an extended target of one million barrels a day by 1995. These were:

- Financing of the required investment. The total capital investment required could be in the order of 40 billion "as-spent" dollars (about 1.5 billion in 1977 dollars annually throughout the forecast period),

- Mobilization of the work force. A peak work force of 15,000 to 16,000 people extending over at least a six-year period would be required,

- Industry/government co-ordination. There often appears to be insufficient communication between different government departments and different levels of government.

Shell said that commercial and economic feasibility depend on three things: that prices available for the plant output would be about at world levels and would escalate sufficiently to offset inflationary increases; that fiscal and royalty arrangements would leave adequate funds with the venture operator; that plants would be operated at a high load factor.

Regarding the optimum size of oil sands mining plants, Shell estimated that about 125 Mb/d is the first level of optimization; increments above that are likely to be in the 65 Mb/d range, with mining optimization being the determining factor. Shell believed that the same sizing would be likely for major in situ plants.

Shell estimated the following schedule for its oil sands mining project for an on-stream target date of 1985:

- formalizing the agreement between the potential consortium partners should be accomplished within a matter of weeks;

- an application would be filed with the AERCB by this fall;

- the necessary government approval that follows from a recommendation of the AERCB would be received during the second half of 1980;

- major construction would start in 1981.

Shell recognized that this was a very optimistic schedule, but it was the company's most-likely case.

Shell estimated that both its mining project and Imperial's Cold Lake in situ project could be built within the same general time frame. Close management of the work forces between the two projects would be required to ensure that peaking did not occur in the same short period of time. Shell believed that the two projects have considerable differences in the construction scheduling and the skills required on site at any particular time. In response to questioning by Board Counsel, Shell stated that it anticipated its project would take essentially the same length of time to construct as the Syncrude project.

With regard to the relative timing of the third mining project and the first in situ project, Shell's witnesses stated that the schedules submitted by their company were a relatively notional sort of estimate, and they would not be disturbed if someone said that it is more likely that the first in situ plant might come on stream before the third mining plant, or that they will come on stream simultaneously.

Sun Oil

Sun Oil submitted that it is unlikely that the net cost to Canada of upgraded crudes will be as high as for imported crude and that we should proceed as quickly as possible to realize the potential from both open-pit mining and in situ processes. Sun Oil stressed that government support must go further to develop realistic policies influencing such major issues as pricing, royalties, taxation, and environmental requirements.

Sun Oil suggested to the Board that the 15 Mb/d expansion being discussed for the GCOS plant should not be included in the Board's base-case forecast. In its own forecasts for the oil sands, Sun Oil did not include such an expansion in its base case. However, it did include a 15 Mb/d expansion for its high case, a case that assumed enthusiastic and prompt support from governments. Witnesses for Sun Oil testified that if the entire GCOS output received the same pricing, royalty, and tax treatment as Syncrude, they would then move the GCOS expansion into the most-likely case.

TCPL, Northern and Central and Consumers'

In studies done for TCPL, and for Northern and Central and Consumers', Foster Research assumed that the Imperial Cold Lake project would commence production in 1986, and that subsequent projects would follow at three-year intervals. The rationale for this projection was the view that major projects must be staged in such a manner that the labour and capital requirements of any new project would be increasing as the requirements for the previous project declined. The inflationary pressures resulting from overlapping of projects would increase construction costs and overheat provincial or regional economies.

Texaco

Texaco Canada assumed that the Shell Canada project would come on stream in 1985 at an initial rate of 50 Mb/d for that year. The ultimate size of the Shell plant was estimated to be 150 Mb/d. GCOS was forecast to increase output from 65 Mb/d to 85 Mb/d. The Syncrude project was forecast to increase its capacity from 130 Mb/d up to 150 Mb/d. The maximum size of the Imperial Cold Lake plant was estimated to be 150 Mb/d. A fourth oil sands mining plant and a second Cold Lake plant were also assumed to come on stream before 1995, each with a production capacity of 125 Mb/d. In addition, two small pilot plants of 10 Mb/d were included in the forecast, one in the Cold Lake area and one in the Athabasca Oil Sands area.

Union Carbide

Union Carbide suggested aggressive development of nonconventional reserves as a very promising alternative when planning Canada's energy future. The maximum development scenario presented called for 11 new and 2 existing Athabasca oil sands plants by 1995. In addition, the company forecast that 4 Cold Lake bitumen extraction and upgrading plants and 2 Lloydminster heavy oil upgrading plants could be in operation by that date. Combined output of these projects would be 1909 Mb/d of synthetic crude oil in 1995.

Union Carbide's studies indicated that sufficient revenue flow would be available to fund the ongoing development of synthetic crude oil. Assuming a 75/25 debt/equity ratio, equity capital of about 21 billion dollars (expressed in current values) would be required for the

construction of these 17 new synthetic oil plants. In order to implement the maximum development scenario, pricing policies would have to insure an adequate return to plant owners, and this could mean the re-allocation of resource revenues from other sources of supply to these synthetic oil projects.

UFAWU

The United Fishermen & Allied Workers Union stated that the weight of evidence before the inquiry as to the reserves of heavy oil and bitumen and the technology capable of transforming these resources into usable crude oil, reinforced its conviction that Canada is capable of achieving self-reliance within a decade, and self-sufficiency by 1995.

AERCB

The AERCB said it believed that technical matters for recovery from oil sands have been resolved and that the economic means to make such operations viable are within reach. The AERCB was satisfied that recent developments on a provincial and national level recognize that dwindling supplies of conventional crude oil would require that greater priority be placed on supplies from Alberta's oil sands. This would be particularly true if Canada's stated energy strategy for self-reliance was pursued.

The AERCB expected that future production from the GCOS plant would be increased to 65 Mb/d by the year 1983. Syncrude was projected to achieve production levels at rated capacity of 125 Mb/d by 1980. An expansion of the plant to a capacity of 195 Mb/d by the year 1985 was foreseen.

Based on recent interest for further development in Alberta's oil sands, the AERCB believed it was reasonable to expect that a third mining plant and the first commercial in situ plant would be developed simultaneously to come into production by 1986. Witnesses for the AERCB testified that discussions with the two principal operators, i.e., Shell and Imperial, have centered on concerns about coincident construction and that consideration would have to be given to individual labour demands during the construction period. The AERCB assumed that beyond 1987 plants would be brought on in three to four-year intervals and that in situ and mining schemes would be alternated. Plant size was estimated to be 210 Mb/d. With regard to the optimum economic size for future oil sands plants, the AERCB based its thinking on the size of a single train being about 70 Mb/d, and that future plants would have three of these trains.

The AERCB stated that it believed its forecast of future production from oil sands to be reasonable, noting that the conditions it attached to make it a reality were somewhat optimistic. Development beyond the forecast level is expected to be limited. Given the logistical constraints and availability of labour and capital, the AERCB did not expect that synthetic crude oil production could reach a level greater than 1300 Mb/d by the year 1995 even under the most optimistic conditions. However, without an environment encouraging development, the AERCB believed that the maximum production that could be expected by 1995 would be 460 Mb/d.

With regard to experimental oil sands schemes, the AERCB expected that the present production level of about 9 Mb/d would peak at about 25 Mb/d within the next ten years.

2.5.2 Views of the Board

The Board's base case for oil sands development approaches the maximum development scenario shown in its February 1977 Report on Canadian Oil Supply and Requirements. In adopting this outlook, the Board has relied heavily on the testimony of Imperial and Shell concerning their respective proposed projects, and on the submission of the AERCB. The Board agrees with these submittors that the proposed development schedules are possible, but has allowed for one year slippage in the Cold Lake in situ project. The Board has also assumed a one-year lag between Cold Lake and the next mining plant to allow for better use of the available work force.

Whether the expected development schedule will be realized depends on the perceived profitability of these ventures. The Board is of the opinion that the world oil supply-demand situation is such that world oil prices will be sufficient to enable economic development of the proposed schemes. Furthermore, the Canadian oil supply-demand situation is such that oil sands development appears highly desirable in order to offset an ever-increasing reliance on imported crude oil. Increasing imports are detrimental to Canada's balance of trade and security of supply and, unless curbed, would require expansion of available import facilities or construction of new facilities. The Board is of the opinion that oil sands development should proceed expeditiously.

In adopting this development schedule, the Board emphasizes that realization of the base case depends on a realistic attitude on revenue sharing from these developments by industry and by the Alberta and Federal Governments. Close co-operation between all parties will be essential to meet the time schedules of the base case.

The Board's forecasts of base, low, and high development cases are shown in detail in Appendix F and are illustrated in Figure 2-12. The base case includes a gradual

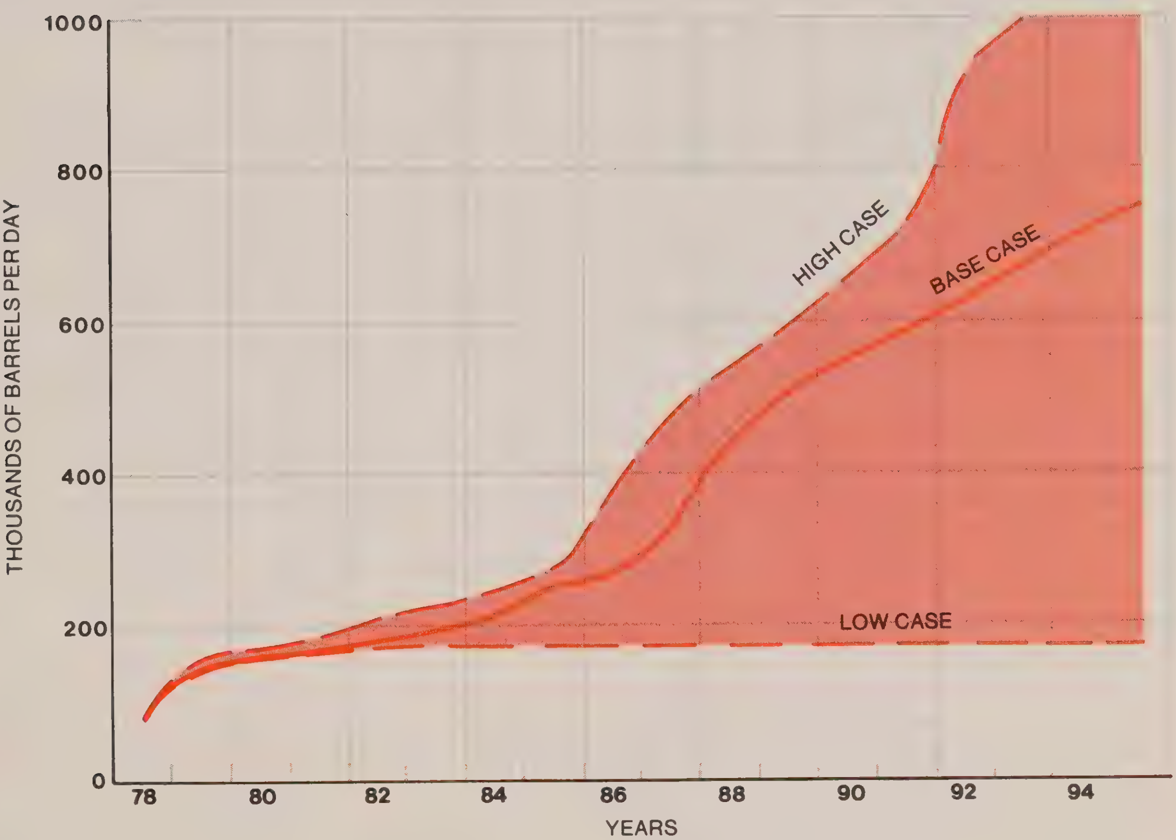


Figure 2-12 **POTENTIAL PRODUCIBILITY FROM OIL SANDS NEB Forecast**

build-up of supply from miscellaneous in situ schemes taking into account projects currently in operation and announced plans to proceed with further development projects. It assumes a GCOS expansion by 1983; a Syncrude expansion by 1985; a Cold Lake in situ project commencing operation in 1987; and the Shell mining project start-up by 1988. Undefined projects are notionally estimated to commence operation in 1991 and 1994.

The low and high cases are provided to illustrate the uncertainties associated with oil sands development. The low case allows no further development after the Syncrude plant, whereas the high case, though only slightly higher than the base case up to 1990, significantly diverges thereafter, thus indicating the potential for accelerated development if pursued energetically.

2.6 FRONTIER RESERVES

2.6.1 Views of Submittors

CPA

The CPA submitted that although frontier discoveries to date have been largely gas, the frontier areas are generally considered to have significant oil potential as well. If Canada's self-reliance objectives are to be achieved, the CPA would like to see a resurgence of frontier exploration activity, which has declined in recent years. This will require resolution of the jurisdictional dispute and an improved outlook for timely development of transportation systems and markets. The CPA also stated that certain negative aspects of the proposed Canada Oil and Gas Act are restraining exploration activity in frontier areas.

Amoco

Amoco's producibility forecasts did not include any additions from the Arctic or Eastern Canada. Amoco believed that in the light of the current controls and guidelines applicable to federal lands, oil production from the frontier areas would not be developed to a significant extent before 1995.

Dome

Dome submitted that the earliest and most cost-effective access to Arctic oil can be gained by the development of Arctic marine transportation systems. The feasibility of Arctic marine transportation should first be

proven by the construction and operation of an Arctic Class ten ice-breaker such as Dome's AML, which could be in operation as early as 1980. With the development of this transportation system, Dome estimated that initial access to Arctic resources could be gained in the mid-1980's. These systems will make possible both a Mackenzie Delta oil supply project and an Arctic LNG project.

Dome stated that its exploration activities in the Beaufort Sea area of the Canadian Arctic have led to significant hydrocarbon discoveries in the past year. However, Dome did not submit any estimates of current and potential reserves.

Gulf

Gulf did not include any frontier oil production in its base case as no large oil accumulations have been discovered to date. Gulf stated however that production from the frontier could start as early as 1990 if the industry has substantial and early (within the next two years) exploration success, and if approvals for transportation and production facilities were granted promptly on confirmation of threshold volumes.

Imperial

Imperial submitted that forecasts of the timing and size of frontier supply are very uncertain because of the high degree of geological and technological uncertainty involved, and because of various jurisdictional, regulatory, and environmental matters that remain unsettled.

With regard to the east coast, the slow exploration pace of the last two years and delays in exploration drilling have caused Imperial to forecast a delay in production of two years from the timing indicated in the 1976 submission. Imperial believes that a reasonable projection for this area is for production rates of 100 Mb/d by the mid-1990's, with a range of anywhere from zero up to 450 Mb/d by the mid-1990's. Imperial believes that to justify the large expenditures that will be required to develop production from this region, it will be necessary to find exceptionally large reservoirs with high production rates.

With regard to the Arctic Islands and the Beaufort-Mackenzie Delta areas, poorer-than-expected results during the past two years have caused Imperial to downgrade its estimates for potential oil supply from these regions. Neither area is expected to have oil production sufficient to support an economic transportation system during the forecast period. Under an optimistic projection, either area could have up to 100 Mb/d of production in the 1990's.

Panarctic

Panarctic believed that the general Bent Horn area has the potential to develop at least 250 to 300 million barrels of recoverable oil. However, its witness testified that the proved category is currently very small. Additional drilling is underway to determine the extent and location of the reservoir. Provided that sufficient production can be developed, Panarctic believes that tankers could be delivering oil to east coast ports within four years at a rate of 50 Mb/d.

Panarctic submitted that until such time as reserves of oil and gas in the Arctic Islands can be established to be commercially marketable, the Board should not consider the availability of oil and gas from this region in its determination of exportable surplus.

Polar

Polar submitted a forecast of frontier primary energy supply of approximately 500 trillion Btu's in 1985 rising to 1600 trillion Btu's by 1995. Polar assumed that these potential frontier supplies would be composed of natural gas rather than crude oil because of the greater success achieved to date in establishing gas reserves. Polar submitted that this situation could change with the advent of early and large oil pool discoveries and the development of appropriate delivery systems.

Shell

Shell submitted that the frontier regions have the potential for large oil and gas reserves. However, because of the current high degree of uncertainty as to the rate at which exploration will proceed, it refrained from making a forecast of oil production from frontier regions.

The uncertainties listed by Shell were the current low level of exploration; reservations regarding the Canada Oil and Gas Act; jurisdictional uncertainties on the east coast off shore; and the question of how rapidly technology can be developed to deal with the hostile frontier environments. Shell said that it was most important that certain provisions of the Canada Oil and Gas Act be reconsidered. The provisions listed were the PIR (Progressive Incremental Royalty); Petro-Canada's 25 percent option; 35 percent Canadian ownership; and the burden of having to make substantial contributions to an environmental study revolving fund without any control on the use of its funds.

Sun Oil

With regard to frontier production, Sun Oil stated that it was doubtful whether the anticipated reward is commensurate with the risk. The proposed federal regulations for frontier oil and the unresolved issue between Newfoundland and the Federal Government have slowed down exploration in these areas. Resolution of these factors is needed promptly.

Texaco

Texaco assumed that oil from the frontier would not be produced in the forecast period 1978 to 1995.

Newfoundland

The Province of Newfoundland submitted that it has a large potential hydrocarbon resource on its continental margin that, along with its major undeveloped hydroelectric sites in Labrador, gives it the potential for developing significant additional energy supplies for use within the Province and the rest of Canada. Using available exploration data, the Energy Division of the Provincial Department of Mines and Energy has estimated the hydrocarbon resource potential to include about 3.5 billion barrels of recoverable oil at a 50 per cent probability level. At the 90 percent and 10 percent probability levels, the potential ranges from 2 billion to 10 billion barrels of recoverable oil respectively.

Newfoundland did not present a definite statement as to the likely time when the potential of the hydrocarbon resource might begin to be realized by production. It stated however that there is a possibility of hydrocarbon production from the Newfoundland and Labrador offshore area within the time frame of the forecast period.

The Province believed that it had temporarily by-passed the difficulties being raised by jurisdictional disputes, by issuing exploratory rights to several industry groups. These rights are for areas to which the companies also hold rights under federal regulations. Several company groups have definite drilling plans for the area and are, in effect, required to drill by the provisions of the governing regulations. If and when oil is discovered, it was the estimation of the Energy Division that about 3 to 15 years would be required from the date of discovery to the date of first production, depending upon the geography and the nature of the hydrocarbon.

2.6.2 Views of the Board

Commercial quantities of oil have not yet been found in any of the frontier areas, although discoveries have been recorded in the Mackenzie Delta, at Bent Horn on Cameron Island in the high Arctic, and on and near Sable Island off the coast of Nova Scotia. Further drilling is required in the frontier areas to provide a reliable assessment of potential. It is the opinion of the Board that it would be too speculative to adopt a potential estimate for these areas at this time, or to attempt to predict reserves additions for the forecast period.

2.7 SUMMARY OF POTENTIAL PRODUCIBILITY FORECASTS

2.7.1 Views of Submittors

Five oil companies examined each supply component and prepared aggregate forecasts for the availability of Canadian crude oil and equivalent. In addition, forecasts were received from each of the three major producing provinces. The forecasts provided by the three provinces have been aggregated and adjusted by the Board to include minor production from other parts of Canada; this is shown with the company forecasts in Figure 2-13.

2.7.2 Views of the Board

The Board's assessments of the contribution from each supply source have been aggregated also and they are compared with the submitted forecasts in Figure 2-13. Complete details of the Board's forecast are provided in Appendix G.

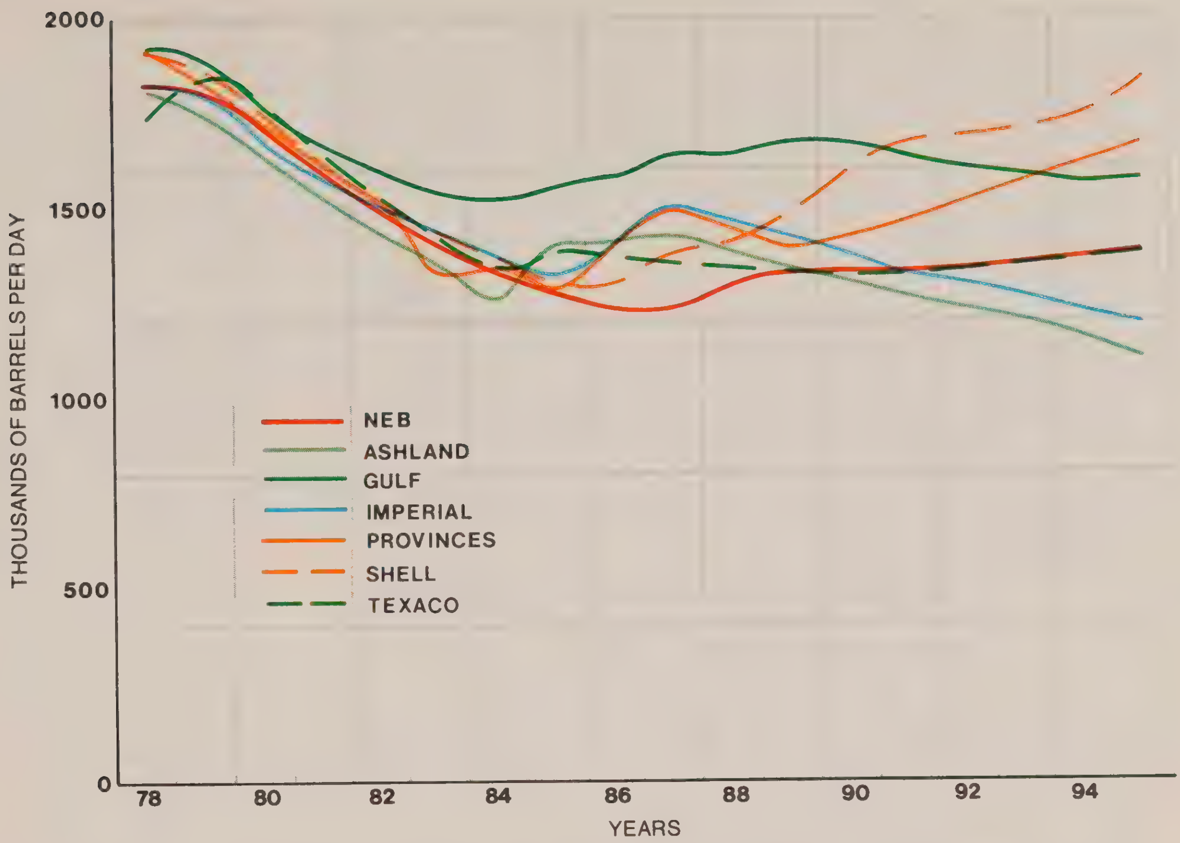


Figure 2-13 **POTENTIAL PRODUCIBILITY OF CANADIAN CRUDE OIL AND EQUIVALENT**
Comparison of Forecasts

The Board expects that the potential producibility of Canadian crude oil and equivalent will continue to decline at an annual rate of approximately five percent until the mid-1980's. The extent to which this rate of decline will be slowed in the late 1980's depends largely on the pace at which the Alberta oil sands deposits are developed. As discussed earlier in this chapter, the Board has assumed an aggressive rate of oil sands development, one which would maintain production at an aggregate level above 1.3 million barrels per day throughout the forecast period.

Although the Board is forecasting a continuing decline in producibility for the next seven or eight years, the situation is somewhat improved from that which the Board expected when it was considering the evidence from the previous oil supply and requirements hearing. The impact of higher crude oil prices for the producer and incentives initiated by both levels of government have resulted in a level of activity above that assumed by the Board in its February 1977 report.

The Board's current forecasts for each supply category are compared with its previous forecasts in Table 2-11. The comparisons need no explanations except to note that about one half of the increases shown for established light crude oil reserves result from the carry-forward effect of production capacity that is shut-in because of export controls. This effect has less significance in the 1985 and 1995 comparisons.

2.8 RANGE OF PRODUCIBILITY SCENARIOS

2.8.1 Views of Submittors

Only Imperial provided an estimate of the variability of its aggregate oil supply forecast. Imperial showed the uncertainty range of its forecast increasing gradually throughout the forecast period. For the year 1995, Imperial's most-likely producibility was slightly under 1200 Mb/d within a range of 1100 Mb/d to 1650 Mb/d.

Additional information provided by submittors regarding individual supply source uncertainty can be found in earlier parts of this Chapter.

2.8.2 Views of the Board

In the preceding sections of this Chapter, the variability of each supply component contributing to total crude oil producibility was discussed. The purpose of Section 2.8 is to aggregate these individual variability estimates to form a more comprehensive understanding of the uncertainties inherent in the Board's crude oil producibility forecast.

The range of the Board's producibility scenarios is summarized graphically in Figure 2-14. The area in the lower left of the graph represents producibility from established oil and pentanes plus reserves and anticipated production from the GCOS and Syncrude projects. The levels of production indicated from these sources, with the exception of Syncrude, have been demonstrated and there is little chance that future production could be below these levels. The average annual rate of decline from these highly secure sources is estimated to be about eight percent.

Table 2-11

FEBRUARY 1977 AND SEPTEMBER 1978 POTENTIAL PRODUCIBILITY FORECASTS

Comparison of NEB Estimates

(Mb/d)

	1979			1985			1995		
	Last Report	This Report	Change	Last Report	This Report	Change	Last Report	This Report	Change
1. Established Reserves of Light Crude Oil	1190	1286	+ 96	543	606	+ 63	181	196	+ 15
2. Established Reserves of Heavy Crude Oil	166	197	+ 31	85	104	+ 19	28	37	+ 9
3. Reserves Additions of Light Crude Oil	15	34	+ 19	63	151	+ 88	114	195	+ 81
4. Reserves Additions of Heavy Crude Oil	31	20	- 11	74	76	+ 2	90	166	+ 76
5. Pentanes Plus	127	127	-	87	102	+ 15	44	48	+ 4
6. Oil Sands	110	145	+ 35	200	255	+ 55	575	755	+180
7. Frontier	-	-	-	-	-	-	-	-	-
8. Upgrading Loss	-	-	-	-	(5)	(5)	-	(5)	(5)
9. Total	1639	1809	+170	1052	1289	+237	1032	1392	+360

The Board's low scenario includes an additional supply component of only about 200 Mb/d from reserves additions to light and conventional heavy crude oil reservoirs and pentanes plus from gas discoveries. As discussed earlier, these minimum estimates assume low discovery rates and no technological advances in improved recovery techniques. No additional oil sands production is included. This scenario also has a high probability that it could be achieved; it is most unlikely that future production could be below this level. The average annual decline rate calculated from this curve is about six percent.

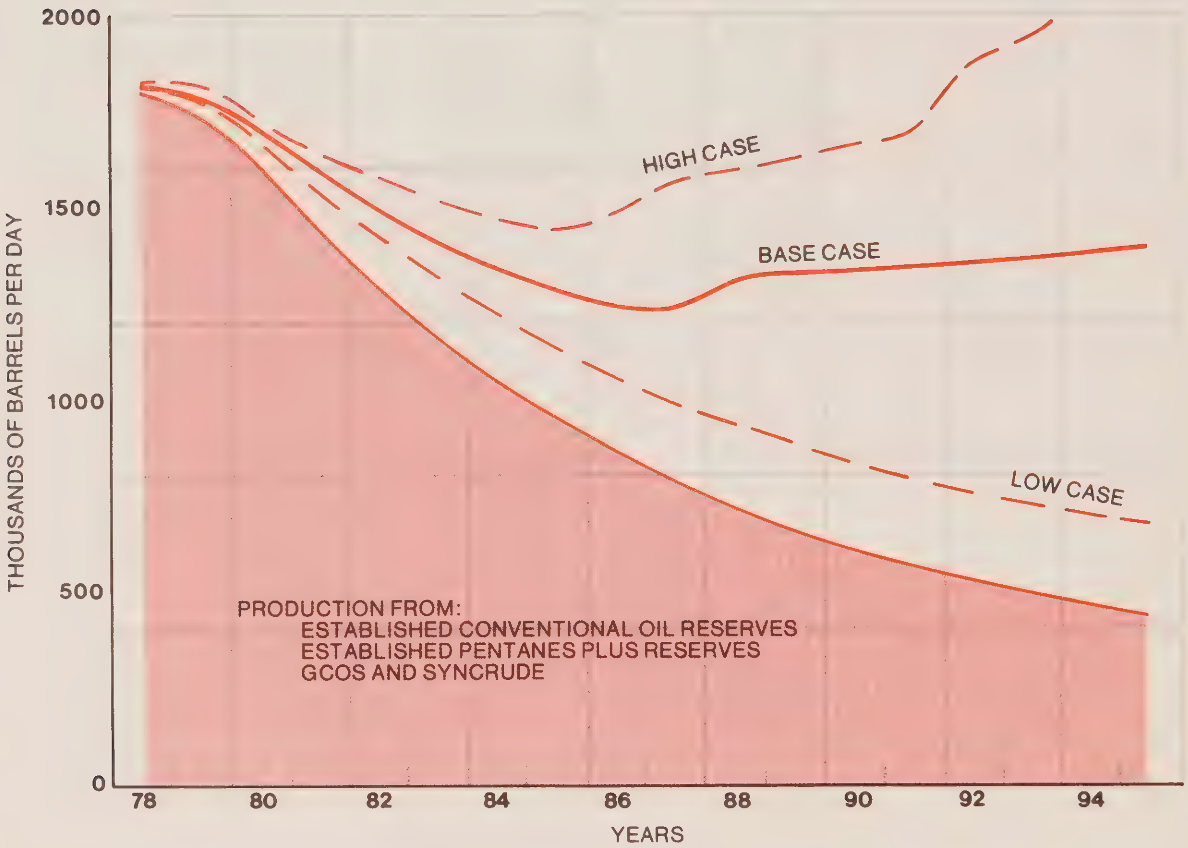


Figure 2-14 **RANGE OF PRODUCIBILITY SCENARIOS NEB Forecast**

The Board's high case assumes that by 1995 about 600 Mb/d will be produced from reserves additions and that about 1000 Mb/d will be produced from new oil sands projects. The Board believes that development of supply beyond these levels could not be achieved under any realistic development strategy.

Figure 2-14 illustrates the tremendous potential that Canada has for the development of new crude oil supplies if conditions are favourable, even without considering the frontier areas. The graph also shows how rapidly Canada's indigenous crude oil production capability could decline if this development potential is not pursued aggressively.

With this range of uncertainty inherent in crude oil supply forecasting, it should not be surprising that the Board's base case has changed significantly since its last oil report. As mentioned in Section 2.7, increased crude oil prices for producers and the effects of incentives initiated by the two levels of government have resulted in a level of activity for exploration and oil sands development well above that assumed by the Board in its 1977 report. If this level of activity is not sustained, the actual production could easily fall towards, or perhaps below, the forecast published in the Board's February 1977 Report on Oil Supply and Requirements.

Although the Board's estimates of the potential for new discoveries and oil sands and heavy oil development are higher than in its last report, its estimates of enhanced recovery potential in light crude oil reservoirs remain unchanged. The Board believes that tertiary recovery may require further attention by governments and industry to realize the potentials shown in Section 2.3.1.2, but that with appropriate strategies these estimates could be exceeded.

Although the Board is pleased that its February 1977 report may have focused attention on the need for accelerated development of new supplies, its current forecast must not be allowed to have the reverse effect. There is no reason to pause in efforts to increase the availability of new indigenous oil supplies from all sources; on the contrary, the Board has assumed that these efforts will increase.

CHAPTER 3

DEMAND FOR TOTAL ENERGY

3.1 INTRODUCTION

To place Canadian demand for oil in a total energy context, submittors were encouraged in the Outline for Submissions to present estimates of oil demand using a total energy-forecasting approach. Submittors using such an approach were requested to provide a breakdown of Canadian energy demand by energy type and to make explicit their basic forecast assumptions such as economic growth, population growth, relative prices of various energy types, market shares, and expansion of energy types into geographic areas not presently using that energy form.

Submittors were requested to provide estimates of conservation included in their base cases, as well as information on additional reductions in demand resulting from conservation measures, which, though feasible, were not anticipated to occur during the forecast period.

In addition, submittors were requested to provide estimates of the extent to which oil could be replaced by other energy forms in the market place, and if possible, to provide estimates of the quantities of each energy type that could replace oil.

Of the 79 submittors, 48 provided information on demand or demand forecasts. Some of the submittors who provided demand forecasts restricted themselves to the market areas or products with which they were primarily concerned. Four submittors - Gulf, Imperial, Shell, and Texaco - provided forecasts of total energy demand for Canada, as well as forecasts of demand for the main refined petroleum products for the major regions in Canada.

This Chapter contains a discussion of the techniques employed by the submittors and the Board in forecasting energy demand, the assumptions used, and the resulting forecasts of energy demand by sector of consumption. The related forecasts of the demand for refined petroleum products are discussed in the next Chapter. The Board's forecast of total energy demand is presented in Appendix H.

3.2 FORECASTING METHODS AND ASSUMPTIONS

In the following, a brief description is provided of the methodology employed by submittors and the Board in developing the total energy demand forecasts. However, no attempt is made to provide an all-encompassing discussion of the methods used by each of the submittors who provided a demand forecast.

3.2.1 Methodology

3.2.1.1. Views of Submittors

Gulf

Gulf's forecast of demand for total energy in the various market sectors was developed through analysis of historical data and the relationship between energy consumption and various economic and demographic variables. The effect of energy prices and the impact of conservation initiatives were also of major importance in estimating future levels of demand. The long-term economic forecast used was developed with the aid of the CANDIDE econometric model of the Canadian economy.

The demand for refined petroleum products was developed as part of the total energy forecast and therefore incorporated Gulf's projections of economic and demographic variables, and also reflected its assumptions regarding interfuel competition.

Imperial

Imperial stated that its projections of energy demand were influenced by a number of factors, the most important of which were the rates of economic growth and the efficiencies with which energy is used. Estimates were made for key factors underlying the requirements for energy. These included population, economic activity, energy prices, and conservation initiatives. For each region, projections of energy demand for the residential, commercial, industrial, and transportation sectors were developed taking into account historical trends in energy consumption and probable changes due to higher real energy prices and initiatives that would reduce demand. The energy demand for each region was divided among competing fuels based on historical patterns and assumptions about future availability and competitive price relationships among fuels.

Shell

Shell's forecast was prepared on a provincial basis using forecasts of economic activity based on employment and productivity for each province within the context of a total-Canada forecast of economic and demographic variables. In preparing its energy demand forecast by market sector, the method employed was to relate demand in each sector to those economic and demographic variables that could be forecast with a fair degree of accuracy. Consideration was also given to interfuel price relationships, availability of fuels in the various regions, and other factors. Finally, results were modified by assessing the impact of various conservation measures.

Sun Oil

Sun Oil did not develop a total energy forecast, but it did provide estimates for those petroleum product categories and geographical areas (Ontario and Quebec) in which it is involved. These product estimates incorporated the expected effect of various energy conservation factors in each of the market sectors, as a result of both price increases and government action designed to reduce consumption. In addition, Sun Oil's forecast of petroleum product demand took into account the effect of interfuel competition as well as expected levels of general economic activity.

Texaco

Texaco's primary energy demand forecast reflected an expected continuation of trends in overall economic and population growth rates, increased energy efficiency, and other conservation measures. Its projection of end-use energy demand was based on forecasts of market sector demand growth prepared after analysis of historical growth rates and the factors upon which demand in the various sectors is functionally dependent, including certain energy conservation initiatives. Demand for individual fuels was considered in the light of historical market shares, anticipated relative prices, and availability of various fuels. Upon calculation of national primary energy and market sector demand, the totals were disaggregated provincially or regionally based on historical consumption patterns and a forecast of relative economic performance.

AERCB

The Alberta Energy Resources Conservation Board submitted a forecast of total oil requirements only, by end-use sector, for the Province of Alberta. This forecast, submitted as a preliminary projection of requirements, was prepared following a public hearing conducted by the AERCB in September and October of 1977 to consider Alberta's total long-term energy needs. The forecast was prepared in the context of total energy demand and was related to specific forecasts of industrial activity and related population growth for the Province.

British Columbia

The submission of the Government of British Columbia included a forecast of British Columbia's petroleum product requirements, which was largely based on the assumptions and conclusions contained in the British Columbia Energy Commission report entitled "British Columbia's Energy Outlook 1976-1991". That report forecast total energy requirements, by sector of final demand, based on specific assumptions as to future population and economic growth. The total energy forecast in each sector was disaggregated by energy type according to the expected capture rates of the various energy forms, determined to a large degree by anticipated relative prices among fuels. British Columbia's forecast of petroleum product requirements used the "Energy Outlook" report, but also incorporated more up-to-date information with respect to such factors as population and economic growth, recent trends in conservation, and energy prices.

Newfoundland

In its submission, Newfoundland presented both a low and a high energy demand scenario for the Province. The low scenario was based on the assumptions that the historical relationship between Gross Provincial Income and Gross National Product would continue, that the Lower Churchill hydroelectric project would not take place in the period to 1995, and that no significant petroleum discoveries would take place. For the "high scenario", which was seen by the Province as a more realistic base forecast, it was assumed that the Lower Churchill project would be completed by the mid-eighties and that major offshore petroleum development would take place by that time. Newfoundland also included in its submission a forecast of its energy requirements that had been prepared by the Federal Department of Energy, Mines and Resources, but which the Province considered to be too low.

Nova Scotia

In its submission, Nova Scotia provided a forecast of total energy demand for Nova Scotia by end-use sector. This forecast was primarily influenced by the expectation of a more-efficient utilization of all energy resources in the future, and the assumption of a shifting of reliance from petroleum to alternative energy sources, combined with a detailed examination of the main areas of consumption in each sector of use.

In addition to a base-case forecast of petroleum product demand, three other scenarios were developed by Nova Scotia: additional conservation, replacement of oil by electricity, and replacement of oil by natural gas. The base-case forecast was further documented in a supporting submission by the Nova Scotia Energy Council, which provided a detailed description of three petroleum product demand cases: maximum, minimum and probable.

To facilitate a comparison with the forecasts of other submittors, Nova Scotia provided estimates of demand for petroleum products in the Atlantic Provinces, which were calculated by applying the growth rates forecast for Nova Scotia to the 1977 petroleum consumption in the four Atlantic provinces, on a product basis.

Ontario

The Ministry of Energy of the Province of Ontario did not provide any projections of total energy demand or oil requirements. However, the Ministry did file at the inquiry copies of three consulting studies, commissioned by the Province, which examined in detail particular aspects of energy demand in Ontario in the residential/commercial, industrial, and transportation sectors.

3.2.1.2 Views of the Board

In developing its estimates of the demand for refined petroleum products, the Board used a total energy forecast methodology. Although the general approach is essentially the same as that outlined in more detail in the Board's February 1977 Report on Canadian Oil Supply and Requirements, considerable research has been carried out in the past year to improve forecasting methods, especially in the residential, commercial, industrial, and road transport sectors.* These improvements are incorporated in the present estimates. In preparing its forecast, the Board has analyzed the evidence received during the inquiry, and this has been given appropriate weight in the Board's estimates.

Energy demand in the residential, commercial, and industrial sectors is linked to population, energy prices, and selected economic variables. Market share forecasts are applied to the estimated total energy demand in each sector to yield demands for individual fuels in each region. The market share forecasts are developed on a judgemental basis, taking into account historical trends, expected relative prices, and various other factors.

In the transportation sector, demand is estimated separately for each of the main transportation modes, namely, air, rail, marine, and road.

Separate estimates are also made for the various types of non-energy use of hydrocarbons including the demand for petrochemical feedstocks. The forecast of energy requirements for the generation of electricity is based on an analysis of each electric utility and its expansion plans.

---

* Papers presented to the Canadian Energy Policy Modelling Conference on May 18-20, 1978 in Vancouver, entitled: "The Energy Demand Forecasting System of the National Energy Board" and "A Model for Forecasting Passenger Car Gasoline Demand in Canada" describe in more detail the present, improved forecasting system.

In the light of the uncertainties inherent in every forecast and also in the prediction of future energy prices and economic growth, the Board has adopted a method of estimating ranges instead of relying on "point" forecasts. However, detailed presentation of the results is restricted to only one demand forecast, referred to as the "Base Case". A brief discussion of the "High Demand" and "Low Demand" cases and of the corresponding assumptions can be found at the end of this Chapter. It is stressed that although only the base case is presented in detail for practical considerations, the Board does not intend to give the impression that it considers a single case, i.e., point estimates, can adequately reflect the complexities and uncertainties of forecasting long-term energy demand.

3.2.2 Economic and Demographic Projections

3.2.2.1 Views of Submittors

For the four submittors who used a total energy approach on a national basis, various views as to the expected economic and demographic projections for Canada are summarized in Tables 3-1 and 3-2.

Gulf, Imperial, and Texaco all forecast lower GNP growth rates compared with their 1976 submissions. The lower rates of economic growth were attributed, in large part, to changes in population and productivity assumptions. Both Gulf and Texaco foresaw energy-related activities providing a significant stimulus to the economy. Texaco believed this would particularly be the case in the latter part of the forecast period.

Shell's forecast was not significantly different from its 1976 submission. Shell continued to expect GNP to grow at a declining rate, largely because of a levelling off and then decline in population growth.

Several other submittors provided forcasts of economic growth for provinces or regions that particularly concerned them. Newfoundland, for example, forecast average annual growth in Gross Provincial Product of 5.2 percent for the 1978 to 1985 period and 6.3 percent for the period 1986 to 1995. Nova Scotia assumed an average annual rate of growth of industrial activity in Nova Scotia of 3 percent over the forecast period. Gaz Metropolitain forecast that Quebec Gross Provincial Product would increase at an average annual rate of 3.5 percent over the 1978 to 1995 period. In British Columbia the average annual rate of growth of Gross Provincial Product that the British Columbia Energy Commission forecast for the period 1976 to 1991 was 4.2 percent.

Table 3-1

REAL GROSS NATIONAL PRODUCT GROWTH RATES

Comparison of Forecasts

(Percent per annum)

	Gulf	Imperial	Shell	Texaco	NEB(4)
1975 to 1980	4.7	3.9(1)	4.2(2)	3.8	4.3
1980 to 1985	4.1	4.5	4.2(2)	4.0	4.5
1985 to 1990	3.4	3.8	3.2(3)	4.0(3)	3.7
1990 to 1995	3.2	3.3	3.2(3)	4.0(3)	3.4

(1) For period 1976 to 1980.
(2) For period 1977 to 1985.
(3) For period 1985 to 1995.
(4) NEB Base Case

Table 3-2

POPULATION GROWTH RATES

Comparison of Forecasts

(Percent per annum)

	Gulf	Imperial	Shell	Texaco	NEB(4)
1975 to 1980	1.2	1.3(1)	1.4(2)	1.3	1.2
1980 to 1985	1.4	1.3	1.4(2)	1.2	1.1
1985 to 1990	1.3	1.2	1.0(3)	1.0(3)	1.1
1990 to 1995	1.0	0.9	1.0(3)	1.0(3)	1.0

(1) For period 1976 to 1980
(2) For period 1977 to 1985
(3) For period 1985 to 1995
(4) NEB Base Case

3.2.2.2 Views of the Board

The Board's projection of the Canadian economy, including the population projections, was prepared using the CANDIDE econometric model of the economy in conjunction with carefully selected assumptions related to such factors as demography, the external environment, and government fiscal, monetary, and exchange rate policies.

The Board's base-case forecast, as set out in Table 3-3, projects fairly strong economic growth through the 1978-1985 period. Reductions in population growth relative to historical experience and expected reductions in productivity growth result in a significant decline in real growth in the economy after 1985. Other features characterizing the projections of the economy in the base case used by the Board are also provided in Table 3-3.

On the demographic side, the annual rate of increase in population is predicted to slow down gradually in the forecast period from an average of 1.6 percent over the historical period 1960 to 1976, to 1.1 percent over the 1985-1995 period. This assumes that the fertility rate will gradually decline from a 1977 level of 2.1 children per female of child-bearing age to slightly less than two children per female by the year 1980, and that the rate stabilizes thereafter. Net immigration in each year of the forecast period is assumed to be 100,000 persons. The resultant population in 1995 is forecast to be 28.4 million.

Table 3-3

PROJECTION OF THE CANADIAN ECONOMY

NEB Base Case

	1977 (Level)	Actual 1960-76	Forecast 1978-80	Forecast 1980-85	Forecast 1985-95	1995 (Level)
		(Percent per Annum)				
GNP ($ 1961 billions)	85.6	5.1	4.6	4.5	3.6	173.5
Population (millions)	23.4	1.6	1.2	1.1	1.1	28.4
Employment (millions)	9.8	3.0	2.1	2.3	1.5	13.6
Households (millions)	7.3	2.9	2.7	2.4	1.6	10.6
Unemployment rate (%)*	8.1	5.5	8.1	7.0	5.5	5.0
CPI** (1961=1)	2.157	1.988	2.703	3.524	5.394	5.394
Personal disposable income ($ 1961 billions)	61.9	5.2	3.2	4.7	3.2	104.4
RDP commercial sector ($ 1961 billions)	36.5	5.4	4.0	4.5	3.4	70.9
RDP industrial sector ($ 1961 billions)	28.3	4.8	5.8	4.4	3.4	58.7

* Period average shown, rather than growth rate.

** Annual level at period end shown rather than growth rate.

3.2.3 Prices

3.2.3.1 Views of Submittors

Most submittors who specified future pricing assumptions projected that Canadian crude oil prices would reach world crude oil price levels in the early 1980's.

Assumptions as to the future course of world crude oil prices differed. Imperial and Shell assumed world oil prices would remain approximately constant in real terms. Gulf projected constant prices in real terms up to the early 1980's, increasing thereafter at 2 percent to 2.5 percent per year. Texaco forecast constant real prices until 1983 followed by real price increases of 4.5 percent per year.

Both Gulf and Texaco assumed natural gas prices would reach Btu parity with crude oil at the Toronto city gate in the early 1980's. Imperial forecast that a "competitive" relationship would exist between natural gas and oil in the major end-use markets in Ontario. However, this competitive natural gas price would be less than Imperial's definition of "full commodity pricing", which was defined as the Btu parity price plus a premium of about fifty cents per million Btu's. Shell and Gaz Metropolitain assumed for their base cases that the present price relationship between gas and oil would continue. Submittors generally agreed that in the Prairie Provinces, natural gas would retain its competitive price advantage over oil products. The British Columbia Energy Commission assumed natural gas prices in British Columbia would increase relative to oil prices on a Btu equivalent basis but would not exceed them.

Most submittors assumed electricity prices would continue to be more expensive per Btu than oil products or natural gas throughout the forecast period, while coal would continue to be relatively cheaper. Texaco projected that although electricity would remain the highest cost form of energy, the growth in electricity rates after 1983 would be slightly lower than the rate of price increases for oil products or natural gas. Nova Scotia believed that electricity in that Province would remain very much more expensive than oil until at least 1982, after which the differential would decrease. By 1986, Nova Scotia foresaw electricity as being price competitive with oil as a heating source.

Ontario testified that it still believed the best way to price Canadian crude oil was by means of the "blended price" mechanism that Ontario first suggested at the Federal-Provincial Energy Minister's Conference in March, 1976. In essence, this proposal would have frozen the price of "old" oil, i.e., crude oil already discovered and in production, while setting the price of "new" oil at a higher level to accommodate the higher costs associated with developing frontier resources, producing synthetic oil from heavy oils or oil sands, or the secondary and tertiary recovery of crude oil from existing fields already producing a base quantity of "old" oil. Finally, the prices of "old" and "new" oils and the prices paid for imported oil would be "blended", so that all Canadians would pay the same "blended" price, subject only to differentials attributable to quality and varying transportation costs.

In its supplementary submission Quebec stated that it favoured a single natural gas price in Eastern Canada. Quebec supported fixing the price of Canadian oil (not used for petrochemical production) at a level equal to or below the landed price in Chicago of international crude oil.

3.2.3.2 Views of the Board

Since price is one of the most important variables in the estimation of both the demand for total energy and the demand for individual fuels, assumptions with regard to the future behaviour of prices played a vital role in forecasts of energy demand. For the base-case forecast, the Board assumed that the world price of crude oil would remain constant in real terms at its 1977 level and that the domestic price of crude oil would rise towards the world price, approaching it by the end of 1981. The forecast assumed that the city-gate price of natural gas in Toronto would increase parallel with the price of domestic crude, maintaining the present price relationship of approximately 85 percent of the crude oil Btu equivalent price.

As previously noted, not only is there an element of uncertainty inherent in every forecast of energy demand, but also in the prediction of future energy prices. It should be emphasized that the price assumptions used represent the Board's assessment of the future direction of prices based on policies and conditions existing at the time of the inquiry.

For calculating energy prices at the burner-tip, using Toronto as the reference point, it was assumed that distribution margins for petroleum products and natural gas will remain constant in real terms. Electricity prices were assumed to increase in real terms until 1981. As a corollary to all the previous assumptions, the real burner-tip price of each fuel remained constant after 1981.

Different price assumptions are made for the high demand and low demand cases that are outlined in the discussion on the potential range of energy demand that is found at the end of the Chapter. The Board notes that if conditions or government policies were to result in energy prices lower than those assumed for the base-case forecast, then energy demand would likely move towards the levels forecast in the high demand case.

3.2.4 Interfuel Competition

3.2.4.1 Views of Submittors

Comparisons of the energy shares projected by various submittors for the residential, commercial, and industrial sectors are found in Tables 3-4, 3-5, and 3-6 respectively.

It must be noted that submittors varied in their definition of each sector. As a result, to obtain a meaningful comparison, the expected direction of the changes in market shares must be examined rather than the actual levels of the market shares forecast.

In the residential sector, as shown in Table 3-4, the market share held by oil is expected to decline by 1995 to a level variously estimated between 14 and 31 percent. Imperial, which estimated the lowest market share, based its projection on its belief that natural gas and electricity would continue to be the preferred energy forms in this sector, even where fuel oil enjoyed some price advantage on a Btu equivalent basis.

Imperial also assumed that a greater energy conservation effect would occur in oil-heated homes due to the fact that in the major residential markets where oil had a significant share, the average age of oil-heated homes was greater than that of gas or electric-heated residences. More scope therefore existed for insulating. Unlike Gulf, Texaco, or Shell, Imperial included in its forecast some expansion of the existing natural gas transmission network into areas of Quebec not presently served by natural gas. Shell testified that it believed some expansion of the re-

gions served by natural gas was likely, but had not included any such expansion in its base-case forecast. Gulf stated that it had not included any gas expansion as it believed such expansion would not be economic.

The commercial sector was characterized by most submittors as the most difficult area to forecast. The submittors generally assumed a moderate growth in the share held by natural gas. Electricity demand in the commercial sector was expected to grow fairly strongly by those predicting a significant decline in oil's share, and more moderately by those projecting a less dramatic drop in oil's share.

In the industrial sector most submittors forecast a moderate decline in the market share held by oil. Natural gas was generally expected to increase its share slightly in the earlier period, with a levelling out or slight decline of its market share in the 1985-1995 period. Gradual growth was forecast for the share of the industrial sector held by electricity.

As the market shares for Quebec and Nova Scotia in Table 3-4, 3-5, and 3-6 illustrate, the market share figures for individual provinces show considerably more variance than for Canada as a whole.

Table 3-4

ENERGY SHARES IN THE RESIDENTIAL SECTOR

Comparison of Forecasts

(Percent of Market)[1]

		Oil	Natural Gas	Electricity	Coal	Other
Gulf	1975	55	26	19	-	-
	1995	30	32	38	-	-[5]
Imperial	1975	46	31	21	2	-
	1985	26	42	30	2	-
	1995	14	47	37	2	-[6]

Table 3-4 (cont.)

		Oil	Natural Gas	Electricity	Coal	Other
Shell	1977	44	32	23	0.3	-
	1985	36	35	29	-	-
	1995	31	35	34	-	-(7)
Texaco(2)	1975	45	31	24	-	-
	1985	29	43	28	-	-
	1995	21	41	39	-	-(8)
Province of Quebec (for Quebec only)	1975	71	6	23(3)	-	-
	1985	39	10	51(3)	-	-
	1990	23	12	65(3)	-	-
Province of(4) Nova Scotia (for Nova Scotia only)	1977	78	-	13	9	-
	1985	75	-	15	10	-
	1995	69	-	23	8	-
NEB	1975	50	25	19	0.4	5.5(9)
	1978	44	27	22	0.3	5.8(9)
	1985	37	30	28	0.3	4.9(9)
	1995	29	32	33	0.3	5.8(9)

(1) Market shares may not add to 100 due to rounding
(2) For residential & commercial sectors
(3) Includes renewable sources
(4) Nova Scotia's base case
(5) Gulf did not include renewable energy in its forecast, but did testify that renewable energy could possibly provide 3 percent to 5 percent of Canadian energy demand by 1995.
(6) Imperial testified that renewable energy sources could provide about 3 percent of residential/commercial requirements by 1985.
(7) Shell testified that by 1995 a maximum of 0.2 percent of total energy demand could be provided by renewable energy sources.
(8) Texaco testified that perhaps 1 percent of total primary energy demand could be met by renewable energy sources.
(9) Includes LPG's (5.5 percent in 1975, 5.8 percent in 1978, 4.9 percent in 1985, 4.3 percent in 1995) and renewable energy.

Table 3-5

ENERGY SHARES IN THE COMMERCIAL SECTOR

Comparison of Forecasts

(Percent of Market)[1]

		Oil	Natural Gas	Electricity	Other
Gulf	1975	29	39	32	-
	1995	12	43	45	-[4]
Imperial	1975	31	41	28	-
	1985	21	42	37	-
	1995	14	42	44	-[5]
Shell	1977	31	35	33	-
	1985	29	37	34	-
	1995	28	38	34	-[6]
Province of	1975	61	9	30[2]	-
Quebec	1985	29	10	61[2]	-
(for Quebec only)	1990	13	11	76[2]	-
Province of[3]	1977	63	-	37	-
Nova Scotia	1985	61	-	39	-
(for Nova	1995	51	-	49	-
Scotia only)					
NEB	1975	28	41	31	-
	1978	26	41	33	-
	1985	20	40	40	-
	1995	16	39	44	1.6[7]

(1) Market shares may not add to 100 due to rounding.
(2) Includes renewable energy
(3) Nova Scotia's base case
(4) Gulf did not include renewable energy in its forecast but did testify that renewable energy could possibly provide 3 percent to 5 percent of Canadian energy demand by 1995.
(5) Imperial testified that renewable energy sources could provide about 3 percent of residential/commercial requirements by 1995.
(6) Shell testified that by 1995 a maximum of 0.2 percent of total energy demand could be provided by renewable energy sources.
(7) Renewable energy

Table 3-6

ENERGY SHARES IN THE INDUSTRIAL SECTOR

Comparison of Forecasts

(Percent of Market)[1]

		Oil	Natural Gas	Electricity	Coal	Other
Gulf	1975	36	33	29	2	–
	1995	31	37	31	1	–(5)
Imperial	1975	36	36	26	2	–
	1985	27	43	28	2	–
	1995	26	42	30	2	–
Shell	1977	35	34	20	11	–
	1985	33	35	21	11	–
	1995	31	36	22	10	–(6)
Texaco	1975	31	33	22	13	–
	1985	33	36	22	9	–
	1995	30	30	25	16	–(7)
Province of Quebec (for Quebec only)	1975	49	12	36	3	–
	1985	38	13	47	3	–
	1990	32	14	52	3	–
Province of[2] Nova Scotia (for Nova Scotia only)	1977	49	–	15	36(3)	–
	1985	43	–	19	38(3)	–
	1995	43	–	28	30(3)	–
NEB[4]	1975	37(8)	34	27	1.9	0.7(9)
	1978	36(8)	34	28	1.5	1.1(9)
	1985	33(8)	37	29	0.7	0.5(9)
	1995	29(8)	38	31	0.2	1.3(9)

(1) Market shares may not add to 100 due to rounding.
(2) From Nova Scotia's base case
(3) Includes wood's share which was 8 percent in 1977, 6 percent in 1985 and 5 percent in 1995.
(4) Total energy for the industrial sector excludes coal used to produce coke and coke oven gas; and excludes requirements for the production of petrochemicals.
(5) Gulf did not include renewable energy in its forecast but did testify that renewable energy could possibly provide 3 to 5 percent of Canadian energy demand by 1995.
(6) Shell testified that by 1995 a maximum of 0.2 percent of total energy demand could be provided by renewable energy sources.
(7) Texaco testified that perhaps 1 percent of total primary energy demand could be met by renewable energy sources.

(8) In preparing its forecast of heavy fuel oil demand, the Board took into account the evidence with regard to expected conversions to hog fuel in the pulp and paper industry.
(9) Includes LPG's (0.7 percent in 1975, 1.1 percent in 1978, 0.5 percent in in 1985 and 0.5 percent in 1995) and renewable energy.

3.2.4.2 Views of the Board

The market shares incorporated into the Board's forecast were developed on a judgemental basis by considering such factors as relative energy prices, relative capital costs of installing heating equipment, and historical and current trends. Evidence presented at the inquiry was important in this judgement process.

The question of extension of natural gas service in Quebec and to the Maritime provinces will be considered in detail by the Board in connection with the anticipated hearing of applications for pipeline certificates by TransCanada PipeLines and Q and M Pipelines Ltd. Pending the disposition of these applications, the Board could not reach conclusions on the economic feasibility of the proposed expansions and therefore had to assume no significant changes in existing service areas. Accordingly, the forecasts included in this report do not reflect any extension of the natural gas service area in the Province of Quebec, into the Maritimes, or to Vancouver Island during the forecast period. If expansion in any of these areas were to take place, the demand for oil as forecast by the Board would be reduced correspondingly.

As previously noted, a comparison of the energy shares, as projected by various submittors and by the Board, is provided in Tables 3-4, 3-5, and 3-6 for residential, commercial, and industrial end-use sectors respectively. For Canada as a whole, the Board anticipates that over the forecast period oil will lose significant market share in the residential and commercial sectors to natural gas and electricity. In the industrial sector, the oil market share is also expected to decline, although not as steeply as in the residential and commercial sectors.

It should be noted, however, that market share behaviour varies considerably between regions, reflecting differences in market situations, expected relative prices, and availability of other fuels. It must also be recognized that it is difficult to make direct comparisons of the Board's estimated market shares with those of the submittors, since the definitions of the residential, commercial, and industrial sectors might not necessarily be consistent, and since varying assumptions were made with regard to extension of natural gas service areas.

3.3 FORECAST OF ENERGY DEMAND

3.3.1 Primary Energy Demand

3.3.1.1 Introduction

Primary energy is the quantity of energy resources as produced in the form of crude oil, natural gas, coal, etc., required to satisfy the demand for energy products by the final consumer, regardless of the manner in which that energy resource is ultimately used (including non-energy uses of hydrocarbons).

Secondary energy is the energy that is received by the consumer, i.e., the energy content of fuels that go into the furnace, the automobile, or other end uses. For most purposes, the details of measurement of primary and secondary energy are less important than an understanding that primary energy requirements are larger than secondary energy requirements. One of the main reasons for the difference is the fact that in using fossil fuels, roughly three units of primary energy are necessary to generate one unit of secondary energy in the form of electricity.

For purposes of its study of trends in primary energy demand, the Board has included a hypothetical component in primary energy demand to correspond with the historical and anticipated use of hydro and nuclear-generated electricity. To calculate this hypothetical component, the Board assumes that electricity generated from hydro and nuclear energy is derived instead from fossil fuels and requires an energy input of 10,000 Btu's per kilowatt hour. This assumption facilitates the study of long-term trends in primary energy demand by freeing the analysis from the influences of changes in the historical or forecast trends in electricity generating patterns insofar as they relate to the split between nuclear and hydro electricity versus electricity generated from fossil fuels.

In brief, primary energy is defined to include:

- energy use in the residential, commercial, industrial, and transportation sectors;
- non-energy use of hydrocarbons (such as petrochemical feedstocks, lubricants, and asphalt);
- energy used in the energy supply industries (such as natural gas pipeline fuel);
- conversion losses in the transformation of energy forms (such as fossil fuels to produce electricity);
- primary electricity (nuclear and hydro) assessed at the fossil fuel equivalent.

The Board's forecast of total primary energy demand is illustrated in Table 3-8 and Figure 3-1.

3.3.1.2 Views of Submittors

Table 3-7 provides a comparison of growth rates for various forecasts of Canadian primary energy demand:

TABLE 3-7

PRIMARY ENERGY DEMAND - GROWTH RATES

Comparison of Forecasts

(percent per annum)

		Oil	Total Energy
Gulf	1975-1985	1.3	3.4
	1985-1995	0.9	2.1
Imperial	1975-1985	0.6	3.3
	1985-1995	1.0	2.9
Shell	1977-1985	2.0	3.1
	1985-1995	1.4	2.1
Texaco	1975-1985	1.9	3.2
	1985-1995	0.9	2.4
NEB	1975-1985	2.0	3.0
	1985-1995	1.3	2.8

Gulf, Imperial, Texaco, and Shell provided information on Canadian primary energy demand, although Shell did not fully break down the oil use involved in converting from primary to secondary forms of energy. Excluding Shell, the estimates of the annual primary demand for oil ranged from 3.9 to 4.1 quadrillion Btu's ("Quads") by 1985. This was about 17 percent lower than the corresponding estimates of primary oil demand that were presented in their 1976 submissions. Total primary energy demand was estimated between 8.6 Quads and 11.1 Quads in 1985. By 1995, the range was 4.3 Quads to 4.5 Quads for oil and 10.6 Quads to 14.8 Quads for total energy. The estimates were about 25 to 30 percent lower than those provided in the 1976 submissions.

Table 3-8

PRIMARY ENERGY DEMAND - CANADA

NEB FORECAST

(Trillions of Btu's)

	1978	1980	1985	1990	1995
Oil	3847	3984	4334	4583	4908
Natural Gas	1634	1770	2093	2336	2701
Coal	778	878	957	1107	1233
Renewable Energy	0	0	0	85	199
Hydro & Nuclear Electricity	2580	2794	3399	4340	5219
Total Primary[(1)] Energy	8840	9426	10784	12451	14259

(1) Totals might not add due to rounding.

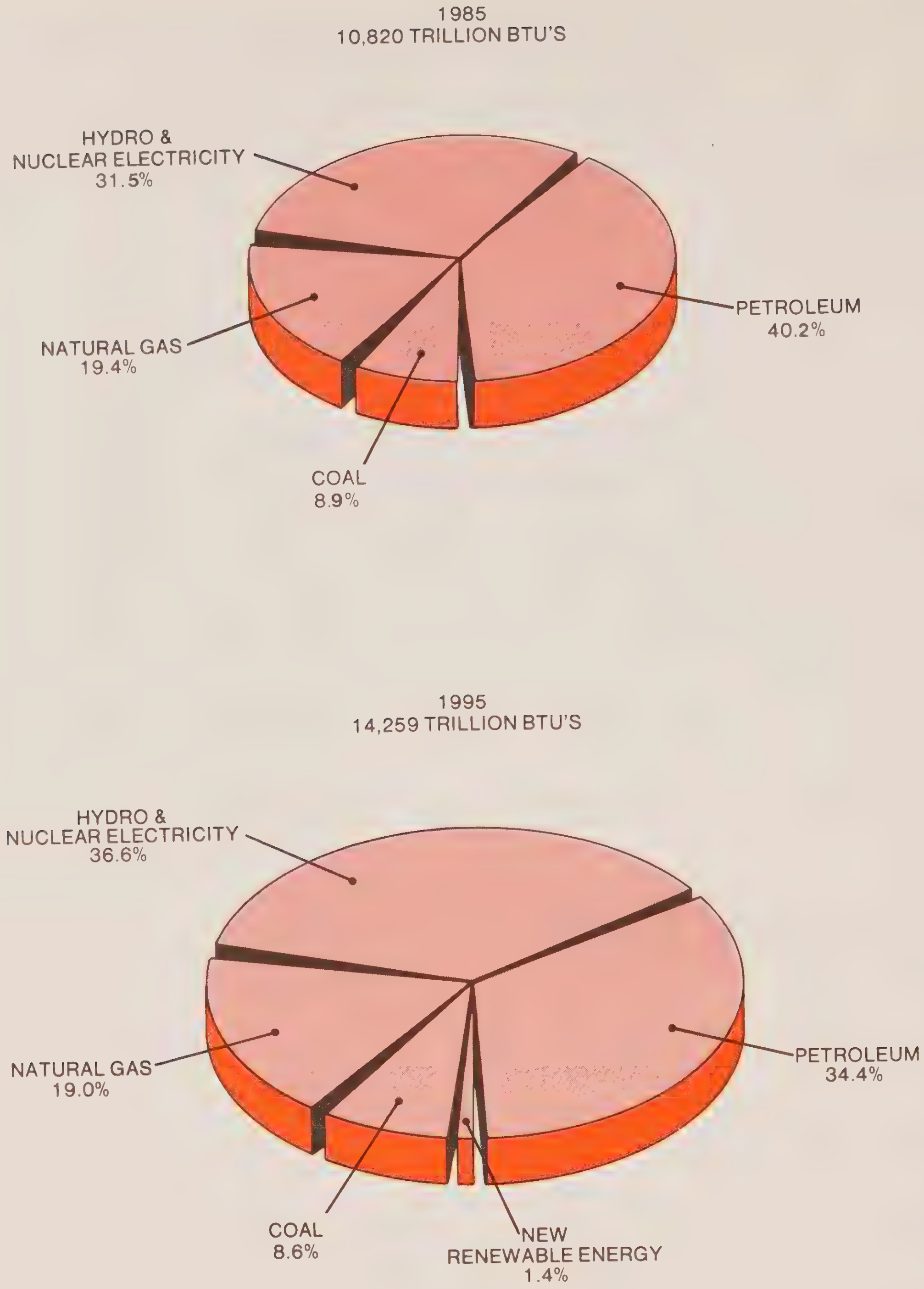


Figure 3-1 **PRIMARY ENERGY DEMAND FOR TOTAL CANADA
NEB Forecast**

3.3.1.3 Views of the Board

The Board's forecast of primary energy demand is summarized in Table 3-8 and Figure 3-1. For the base case, the average annual growth rate for primary energy demand is approximately 2.9 percent over the forecast period.

Primary oil demand is forecast by the Board to grow more slowly than primary energy demand, with an average annual growth rate of 1.6 percent over the forecast period. The share of total primary energy demand supplied by oil is expected to decline from 46.6 percent in 1975, to about 35 percent in 1995. This decrease in the market share for oil is the result of, among other things, increased market penetration by other energy forms. This is reviewed in the following section, which presents the NEB's energy demand forecast by sector; details of this forecast are provided in Appendix H.

The Board's forecast of total primary energy demand is very similar to its forecast prepared for the 1977 report on oil supply and requirements. The present forecast of primary oil is, however, somewhat lower. The reasons for this are discussed in detail in subsequent parts of this Chapter and in Chapter 4.

While the present report makes various comparisons of its supply and demand forecasts with those of the 1977 Oil Report, the reader may be interested in comparing the Board's present energy demand forecasts with those contained in the "Reasons for Decision: Northern Pipelines". The Board's base-case forecast of total primary energy demand for 1995 is now some 14.3 Quads whereas the forecast for the Northern Pipelines Decision was about 16 Quads. There are several major reasons for this difference. First, as a result of evidence submitted to this inquiry and its own further analysis, the Board has reduced its forecast of electricity demand. Second, the Board's current base-case macro-economic forecast predicts a level of GNP approximately seven percent lower for 1995 than was forecast for the Northern Pipelines report.

In comparing the present forecast with that used for the Northern Pipelines Decision, it should be noted that the present forecast of natural gas demand is about 8.3 percent lower for 1985 and 11.7 percent lower for 1995. Over one-third of this reduction in forecast natural gas demand for both 1985 and 1995 stems from reduced natural gas requirements for electricity generation, and another one-third comes from reduced industrial demand. Both of those reductions are consistent with new evidence available to the Board through the current inquiry.

3.3.2 Energy Demand by Sector

3.3.2.1 Views of Submittors

Information was provided by Gulf, Imperial, Shell, and Texaco on total energy demand for Canada by sector. For each sector, the relevant growth rates for these forecasts, as well as that of the Board, are summarized in Table 3-9. As previously noted, definitional differences may exist between submissions for the various sectors.

In the residential sector, there was a difference of opinion regarding expected growth. While Imperial indicated a steady growth in energy demand throughout the forecast period, Gulf indicated an increase in the average annual growth rate for the period after 1985. Shell predicted that the annual growth would decline in the latter half of the forecast period. Texaco did not provide separate estimates for the residential sector, but combined its forecast with that of the commercial sector.

In the commercial sector, there was general agreement among submittors that the growth in energy demand would slacken somewhat in the second half of the forecast period, but generally would continue to grow at rates considerably higher than in the residential sector.

For the combined residential/commercial sectors, growth rates were expected to remain reasonably steady throughout the entire period, except in Shell's forecast, where substantially reduced energy growth was predicted for both sectors.

For the industrial sector, there was general agreement among submittors that annual rates of increase would exceed those of all the other market sectors. Submittors generally indicated that there would be some slackening of demand in the latter half of the forecast period compared with the first half, but that strong growth would continue.

For the transportation sector, all the submittors predicted a decline in growth rates, primarily influenced by the absolute decline in the forecast demand for motor gasoline.

Table 3-9

ENERGY DEMAND GROWTH RATES - BY SECTOR

Comparison of Forecasts

(percent per annum)

		1975-1985	1985-1995
Residential	- Gulf	0.8	1.6
	- Imperial	1.6	1.6
	- Shell*	1.7	1.0
	- Texaco	-	-
	- NEB	0.9	2.2
Commercial	- Gulf	3.9	3.0
	- Imperial	3.1	2.7
	- Shell*	2.3	1.4
	- Texaco	-	-
	- NEB	3.4	3.5
Residential/ Commercial	- Gulf	2.1	2.3
	- Imperial	2.1	2.0
	- Shell*	1.9	1.2
	- Texaco	2.5	2.6
	- NEB	1.9	2.8
Industrial	- Gulf	3.7	3.3
	- Imperial	3.5	3.0
	- Shell*	3.7	2.7
	- Texaco	4.5	3.4
	- NEB	2.6	2.7
Transportation	- Gulf	1.4	0.7
	- Imperial	1.4	1.1
	- Shell*	1.7	1.2
	- Texaco	1.7	0.6
	- NEB	2.1	1.3

* base year for calculation is 1977

Note - Definitional differences may exist between submissions for the various sectors.

3.3.2.2 Views of the Board

Residential Sector

The demand for energy in the residential sector is mainly related to requirements for space-heating, water-heating, lighting, and electric appliances in single-family homes and in small apartment buildings. Growth in total energy demand is expected to be moderate, averaging 1.6 percent per year over the forecast period 1978 to 1995. The response of consumers to higher energy prices and to government-sponsored conservation programs will result in slower growth in energy demand mainly in the period before 1985. After 1985, demand is forecast to grow slightly faster, as growth in real personal disposable income per household and in the number of single dwellings continues, although at reduced rates.

Oil demand in the residential sector is expected to decrease over the forecast period, with an overall rate of decline of one percent per year. This decrease occurs as a result of the slow growth in total energy demand in this sector, assumed increases in the operating efficiencies of oil home-heating systems, and as a result of increased market penetration by natural gas and electricity. The Board's estimate of the oil share in the residential sector is set out in Table 3-4.

Commercial Sector

The commercial sector covers a heterogeneous mix of energy demands, including requirements for energy used by large apartment and office buildings, schools, hospitals, shopping centres, and small commercial establishments. Growth in total energy demand is expected to remain fairly steady, averaging 3.7 percent per year over the forecast period, in response to continued growth in real commercial product in the range of 3 percent to 4.5 percent per annum. These figures take into account Board projections that as a result of higher energy prices, energy demands will be about 24 percent lower by the end of the forecast period than they would otherwise have been.

The demand for petroleum products in the commercial sector is expected to remain relatively constant, with an average annual growth rate of 0.5 percent over the 1978 to 1995 period. The demand for oil will grow at a much slower rate than the demand for energy, mainly as a result of

increased market penetration by electricity. Although the oil share of the commercial sector has already declined significantly, to about 26 percent in 1978, it is expected to further decline to 16 percent by 1995.

Industrial Sector

As stated earlier in the report, considerable effort has been made over the last year to improve virtually every aspect of the Board's energy demand forecasting system. One major area of improvement in the industrial sector is that new total energy forecasting equations have been developed. In this regard, two specific refinements might be noted. First, separate equations have been estimated for each region of Canada. This has led to improved regional forecasts, since the different industrial structures of the various regions have been more appropriately taken into account. Second, more recent data have been utilized in developing the equations. One result is that estimates of the effect of higher energy prices are improved.

The Board agrees with the evidence presented that the demand for energy in the industrial sector will grow less rapidly in the future than it did historically. The base-case forecast implies an average annual growth in total industrial energy demand for Canada of 2.7 percent between 1978 and 1995, as contrasted with 5.3 percent between 1958 and 1974. The major contributing factors are higher energy prices, increased efficiency of energy use, and lower expected growth in industrial economic activity. In general, the growth in energy demand is expected to continue to taper off until about 1990, when it picks up slightly. This reflects the expected trend in industrial economic activity. Also, the effect of higher real energy prices in the 1970's and early 1980's is expected to have had its full impact by around 1990.

It is expected that there will be significant interregional differences in industrial energy demand growth. Such differences are consistent with historical experience and reflect, in part, expectations regarding different regional rates of growth in industrial activity.

The projections of future demand for oil in the industrial sector differ depending on the particular product and region under consideration. In general, however, oil demand in the industrial sector is expected to grow at an average annual rate of 2.2 percent between 1978 and 1995 for

Canada as a whole, a less rapid growth rate than that of total energy. This reflects the expectation that the market share of oil will generally decline slowly in the industrial sector with both natural gas and electricity making gradual inroads.

Transportation Sector

The transportation sector has been subdivided to consider road, rail, air, and marine transportation separately. The results for each of these segments are discussed below.

Road transportation demand for energy consists of demand for motor gasoline and diesel fuel oil. Although motor gasoline demand increased at an average annual rate of 5 percent per year during the period 1966-1976, it is estimated to increase at an average annual rate of only 1.7 percent per year to 1980, after which it is forecast to decline at an average annual rate of 0.5 percent. The Board agrees with the considerable evidence presented that the declining trend in motor gasoline consumption is caused by significant improvements in the fuel efficiencies of automobiles and gasoline trucks and by the substitution of diesel fuel oil for gasoline.

The potential for improving fuel efficiencies of diesel trucks appears rather limited. This factor, combined with assumed substitution of diesel fuel oil for gasoline, particularly after 1985, explains the vigorous rates of growth estimated for road consumption of diesel. It is estimated that road consumption of diesel will increase at an average annual rate of eight percent between 1978 and 1995.

Total energy demand (motor gasoline plus diesel fuel oil) in the road transportation sector is estimated to increase at an average annual rate of 0.9 percent during 1978-1985 and at 0.7 percent per year during 1985-1995.

The total energy requirements for rail transportation are forecast to grow at an average annual rate of 2.3 percent from 1978 to 1995, while the demand for diesel fuel in this sector is projected to grow at an average annual rate of 2.4 percent over the same period. These growth rates are lower than the economy's growth rate over the forecast period.

Aviation turbo fuel constitutes the principal fuel used in the air transportation sector. Relatively strong growth is anticipated for this petroleum product, particularly in the early portion of the forecast period. Aviation gasoline requirements, on the other hand, are projected to remain relatively constant until 1985, and then to increase moderately through 1995. The lack of growth in aviation gasoline demand until 1985 reflects the expected continuation of replacing piston-type aircraft by turbo aircraft. After 1985, it is forecast that such replacement effects will be minimal. The total energy demand in the air transportation sector is forecast to grow at an average annual rate of 4.4 percent over the forecast period 1978 to 1995.

In the marine transportation sector, energy demand is expected to grow at a decreasing rate, reflecting the economic growth pattern underlying the demand forecast. The Atlantic region shows the strongest growth rate in marine energy demand. Over the forecast period 1978 to 1995, the total marine energy demand is projected to grow at an average annual rate of 2.7 percent for Canada, while for the Atlantic regions the growth rate is 4.4 percent.

Oil accounts for almost all of the energy consumed in the transportation sector. Total energy requirements in the sector are estimated to increase at an average annual rate of 1.8 percent from 1978 until 1985 and at 1.3 percent thereafter.

3.4 ENERGY CONSERVATION

3.4.1 Introduction

In the Board's Outline for Submissions, submittors were requested to indicate the extent to which their forecasts of demand reflected the effects of conservation. They were also encouraged to comment on and quantify any additional reductions in demand, by product category, resulting from conservation measures that, though feasible, were not anticipated to occur during the forecast period.

A general review of the information received and the opinions expressed by the submittors is provided in the following sections, along with the views of the Board.

3.4.2 Views of Submittors

Gulf, Imperial, Shell, and Texaco estimated that, compared with historical trends, significant energy conservation savings would be realized over the forecast period. Gulf foresaw a reduction in the average annual growth rates for refined petroleum products to 1.2 percent over the 1975 to 1995 period, compared with the 4.1 percent rate experienced over the 1965 to 1975 period. Imperial predicted total secondary energy demand would be reduced by 20 percent in 1985 and 30 percent in 1995 over the levels projected, using historical trends. Shell, on a similar basis, estimated savings in the industrial market sector of 6 percent in 1985 and 9 percent in 1995. Energy savings in other market sectors were expected to be about 18 percent in 1985 and 25 percent in 1995.

AERCB

The Alberta Energy Resources Conservation Board expected conservation measures would decrease the use of oil relative to what would be required under present consumption patterns, by 15 percent in 1995 in the residential/commercial sector and 5 percent in the industrial category. The greatest potential for energy conservation savings was seen to be in the transportation sector, where by 1995 savings of 45 percent for motor gasoline and 16 percent for diesel fuel were estimated.

BCEC

The British Columbia Energy Commission believed that building code changes could reduce oil consumption for residential heating in British Columbia by 2.5 percent in 1985 and 7.5 percent in 1995. In addition, a major insulation retrofitting campaign could achieve a further average 20 percent reduction in oil consumption in the existing housing stock by 1985. In the commercial sector, under similar assumptions, the savings in energy consumption in new buildings were estimated to be 50 percent, with a potential 15 percent saving in the existing stock of buildings from a retrofitting campaign. In the industrial sector, British Columbia forecast a decline in the residual fuel oil consumption of the forest industry due to increased use of hog fuel, i.e., wood waste. An "energy bus" campaign to audit small industries' practices in energy utilization was estimated to have the potential to result in energy savings in the order of 20 percent.

Nova Scotia

Nova Scotia developed a detailed energy conservation case based on specific assumptions with respect to the consumption of motor gasoline, diesel fuel, heating fuel, and heavy fuel oil. Nova Scotia also examined conservation of electricity and its effect on fuel oil used for electric power generation. The resultant conservation case indicated a potential saving in Nova Scotia, for all products, of 2.4 percent (about 2 Mb/d) rising to 3.3 percent (about 3 Mb/d) in 1985 and 3 percent (3.5 Mb/d) in 1995.

Ontario

Ontario testified that in 1974 it established a goal, and commenced the implementation of programs aimed at reducing provincial secondary energy demand growth to 3.5 percent per year, or less, by 1980. Ontario believed this goal would be met, citing as an example Ontario Hydro's reduced target annual growth rate for electricity demand of 5.5 percent between 1978 and 1986 and 4.5 percent thereafter. This compared with a historical electrical demand growth rate of 7 percent annually.

Quebec

In its supplementary submission, Quebec estimated that the more efficient use of energy should permit a reduction of about 23 percent in the Province's forecast energy consumption in 1990.

Saskatchewan

While Saskatchewan did not prepare a base-case forecast or an explicit estimate of potential energy conservation savings, it did outline existing or possible conservation measures that could have an impact on demand for petroleum products during the forecast period. Saskatchewan estimated that these measures could lead in the residential sector to an average fuel saving of 30 percent in homes that upgrade insulation levels. It was also believed that changes in tillage practices could have a significant impact on the demand for motor gasoline and diesel fuel used for agricultural purposes.

SPEC

The Canadian Scientific Pollution and Environmental Control Society put forward a list of recommendations for energy demand management that included incentives to upgrade the energy efficiencies of industry, commercial buildings, and personal residences, measures to encourage mass transit, and measures to ensure greater efficiencies in appliances.

CTA

The Canadian Trucking Association submitted that there were two principal sets of policies within the domain of provincial governments that could lead to increased energy conservation by the trucking industry. The first would be to apply and enforce reduced maximum speed limits for trucks. The second would be the standardization between provinces of the maximum weights and dimensions permitted for truck combinations.

Gaz Metro

Gaz Metropolitain estimated that if energy conservation measures were implemented, natural gas consumption in the Province of Quebec could be reduced by about 4 percent in 1978, rising to 12 percent in 1995, compared with its base-case forecast.

SOS

The North Coast Committee to Save our Shores submitted that research programs and practical demonstrations of renewable energy alternatives and energy conservation programs exist in many areas of the world. It believed conservation and renewable energy strategies to be economically sound, socially beneficial, and environmentally appropriate when compared with large-scale, non-renewable energy projects.

Polysar

Polysar stated that it was aiming to improve its own energy efficiency by 35 percent by the end of 1980 relative to 1972 performance. Polysar believed this would require major capital outlays, and that its decision to invest would depend on the predictability of energy costs and on the assurance that consistent energy policies would be followed.

Brian Redway

Brian Redway compared energy use in Sweden with Canadian energy consumption and suggested that if the price of energy is administered in such a way as to dampen demand, there is scope for Canadians to curtail their energy consumption, especially of oil. He believed that if the Canadian government chose to implement an energy conservation policy based on control of energy prices, Canadian domestic per capita consumption need not exceed current levels and could be encouraged to decline to a level comparable to the present Swedish figures within 15 years.

Smithers

The Smithers Conservation Centre stated that there was great potential for reducing oil demand by employing some fairly basic energy conservation practices. Based in large part on the report, "Energy Conservation in Canada: Programs and Perspectives", published by the Federal Department of Energy, Mines and Resources, Smithers outlined various examples and provided specific recommendations. It was also submitted that energy conservation programs had a high employment potential. Smithers recommended that increased funding be provided for research and development in energy conservation techniques.

Sun Oil

Sun Oil examined the potential savings of various refined petroleum products in Ontario and Quebec from energy conservation measures beyond those assumed in their base case. These estimated reductions amounted to 3.5 Mb/d of light fuel oil in 1985 and 5.5 Mb/d in 1995. Heavy fuel oil savings were predicted to be 1.5 Mb/d and 2 Mb/d in 1985 and 1995 respectively.

TCPL

TransCanada's submission assumed energy conservation measures would reduce energy demand by 1 percent a year in the residential and commercial sectors through 1985, and 0.5 percent per year from 1985 to 1995.

Union Carbide

Union Carbide stated that the goal of the Chemicals Industry Task Force for Energy Conservation was to further increase the energy efficiency in the industry from the 12.5 percent improvement in Btu's per pound of output already achieved in January 1978, to 17 percent in 1980. Union Carbide's own goal was to attain a 20 percent weighted average energy efficiency improvement for all its operations in Canada. In the period 1980 to 1995, Union Carbide foresaw industrial energy conservation being oriented more towards process retrofitting and new technology as opposed to the "housekeeping" efforts that have characterized the program to date.

UBCIC

The submission of the Union of B.C. Indian Chiefs stated that conservation was the least-expensive means to alleviate pressures for energy delivery. The UBCIC believed that there were measures to reduce the demand for oil, natural gas, and electricity that would not affect the "life-style" of Canadians or their standard of living. The UBCIC submitted that the lack of government policies to accelerate energy conservation had the effect of placing pressures on Indian people and Indian lands resulting in a reduced standard of living for Indian people, whose standard, insofar as common amenities are concerned, was already among the lowest in Canada.

UFAWU

The United Fisherman and Allied Workers' Union advocated a number of measures to minimize energy demand growth. Recommendations included government action to ensure the manufacture of smaller, more efficient automobiles, the encouragement of the development and use of mass transit systems, the development of a national power grid, and revision to the pricing system for electrical power consumption.

3.4.3 Views of the Board

In developing its forecast of energy demand, with the exception of requirements for the transportation sector, the Board assumes that price is the main impetus towards energy conservation, and, therefore, that most conservation of energy will be in response to price changes. Estimates of future reduction in demand were developed through the use of price elasticities estimated from historical data.

In the road transportation sector, conservation is assumed to occur both as a result of price increases, and as a result of legislation designed to reduce energy consumption (e.g., fuel economy standards for new cars). For some subsectors (e.g., rail, air, and marine), price elasticities were not estimated and conservation estimates were determined judgementally. Conservation in the residential sector includes both the effect of estimated price elasticities and assumed higher efficiencies for oil-heating equipment. In addition, the impact of government-sponsored home-insulation programs, over and above the price effect, has been taken into account by the Board in developing its forecast.

It could be argued that price-driven conservation already incorporates the effect of some government-sponsored energy savings efforts. Much of the current and planned government conservation effort is directed toward information dissemination. Such measures could be considered as being supportive in nature, i.e., reinforcing the reduction in demand due to higher prices and ensuring that such reductions will in fact materialize. Some elements of government-sponsored conservation programs, such as subsidies and incentives, reduce energy demand more than would occur as a result of the prices alone. As mentioned previously, such conservation effects have been considered by the Board in developing its estimates of energy demand reduction.

The Board recognizes that there exists a potential for larger savings, as evidenced by the submissions and testimony, but believes that it should not speculate in estimating such additional conservation, which, while possible, is unlikely to be achieved without significant changes in effective prices.

In determining what the level of energy demand might be without the expected conservation efforts, the Board adopted the same assumptions used in its base-case forecast, with the exception of those relating to energy prices. For its no-conservation case, ("Export Formula Case"), the Board assumes that energy prices remain constant in real terms at the levels that prevailed at the end of 1972. As stated in previous reports, it should be emphasized that a decrease in the demand for a particular fuel arising from substitution by other forms of energy is not properly classified as conservation.

Conservation in the residential sector, as measured by the decrease in energy demand between the Board's export formula case and the base case, is estimated to be about 11 percent in 1980 and 17 percent in 1985. After 1985, it is expected to increase only slightly, since much of the impact of higher energy prices and government-sponsored conservation programs has been assumed to occur before then. The expected percentage saving in oil products is higher than for total energy, reaching 24 percent in 1985 and 28 percent in 1995. This is the result of assumed improvements in the operating efficiencies of residential oil-heating systems, in addition to the general effect of consumer response to price increases.

For the commercial sector, the Board estimates that both total energy and oil demand will be reduced by 18 percent in 1985, and by 24 percent in 1995, as a result of higher energy prices.

For the industrial sector, total energy demand is expected to be reduced by 18 percent in 1985, and 28 percent in 1995, compared with the Board's export formula case. Similar reductions, as a result of higher energy prices, are expected for oil products.

In the transportation sector, virtually all of the energy demand is met by petroleum products. For this sector overall, energy conservation savings are expected to be 20 percent in 1985, and 35 percent in 1995, with the greatest potential for reduction in demand expected for the road transportation sub-sector.

Motor gasoline demand is expected to be reduced considerably as a result of higher gasoline prices and significant improvements in the fuel efficiencies of automobiles and gasoline trucks, and also as a result of other conservation initiatives. Reduction in demand for motor gasoline is expected to be 26 percent in 1985, and 48 percent in 1995. The potential for improving fuel efficiencies of diesel trucks appears more limited, and, consequently, the combined reduction in motor gasoline and diesel fuel for the road transportation sub-sector is projected to be 24 percent in 1985 and 40 percent in 1995.

In comparison to road transportation, the opportunities for energy conservation in the rail, air, and marine sub-sectors do not appear to be as great, but, nevertheless, the expected reductions are significant. For these combined sub-sectors, the saving is projected to be 8.4 percent in 1985, and 14 percent in 1995.

With respect to the export formula case, further details on the demand for total energy and total oil, by sector of consumption, are provided on page 3 of Appendix H. Total petroleum product demand under this case is also included in the tables of Appendix I to facilitate comparison with the Board's base-case forecast.

3.5 POTENTIAL RANGE OF ENERGY DEMAND

As in previous reports, the Board has adopted the procedure of developing high and low scenarios of energy demand to bracket its base-case forecast. Given the uncertainties inherent in making long-term projections, it is useful to develop a range of demand possibilities rather than a single point estimate.

The approach used to estimate the range of energy demand is to postulate alternative values for the major assumptions that underlie the forecast. These are the macro-economic and demographic conditions and energy prices. The assumptions underlying the base-case energy projection are considered as the "most likely". The assumptions underlying the high and low demand cases are considered to be possible but less likely than those of the base case.

Set out below is a brief description of the major assumptions underlying the high and low demand cases, followed by a short discussion of the results for total primary energy demand. The results for oil demand are discussed in Section 4.9 of the report.

With regard to energy prices, in the high demand case it is assumed that the real price of international crude oil decreases by approximately five percent per annum, while in the low demand case the real price is assumed to increase by approximately five percent per annum. These assumptions are analogous to postulating that the real burner-tip energy prices decrease or increase relative to the base case by approximately four percent per annum, starting in 1978 and continuing throughout the forecast period. This is assumed to be the case for each region, market sector, and energy type.

Regarding economic-demographic conditions for the low demand case, the base-case assumptions are used. The Board's base-case economic projection, discussed in Section 3.2.2, may be described as the most-likely state of the Canadian economy expected to prevail in the future, given the economy's current state, a knowledge of its past behaviour, and a best estimate of the future values for exogenous events such as external environment, immigration rates, productivity, etc.

For the high demand case, a more optimistic economic-demographic outlook is portrayed. This case differs from the base case in that it is assumed that all exogenous events in the future will turn out to be conducive to real economic growth. In this sense, the high demand case may be thought of as an optimistic scenario, still, however, in the realm of the possible, but less likely compared to the base case.

Since the rate of growth of real GNP is approximately equal to the sum of the rate of growth of employment and of productivity, different assumptions regarding both these variables were made to produce the high demand case. Table 3-10 provides values of these variables for the different scenarios.

Table 3-10

ECONOMIC PROJECTIONS

Range of Scenarios

NEB Forecast

(Average annual growth rates)

Period	Employment		Productivity		GNP	
	High	Base*	High	Base*	High	Base*
1978-80	2.2	2.0	3.0	2.7	5.1	4.6
1980-85	2.7	2.3	2.3	2.1	5.0	4.5
1985-90	2.1	1.7	2.3	2.0	4.5	3.7
1990-95	1.6	1.4	2.2	2.0	3.7	3.4

* The economic projection for the low demand case is the same as the economic projection for the base case.

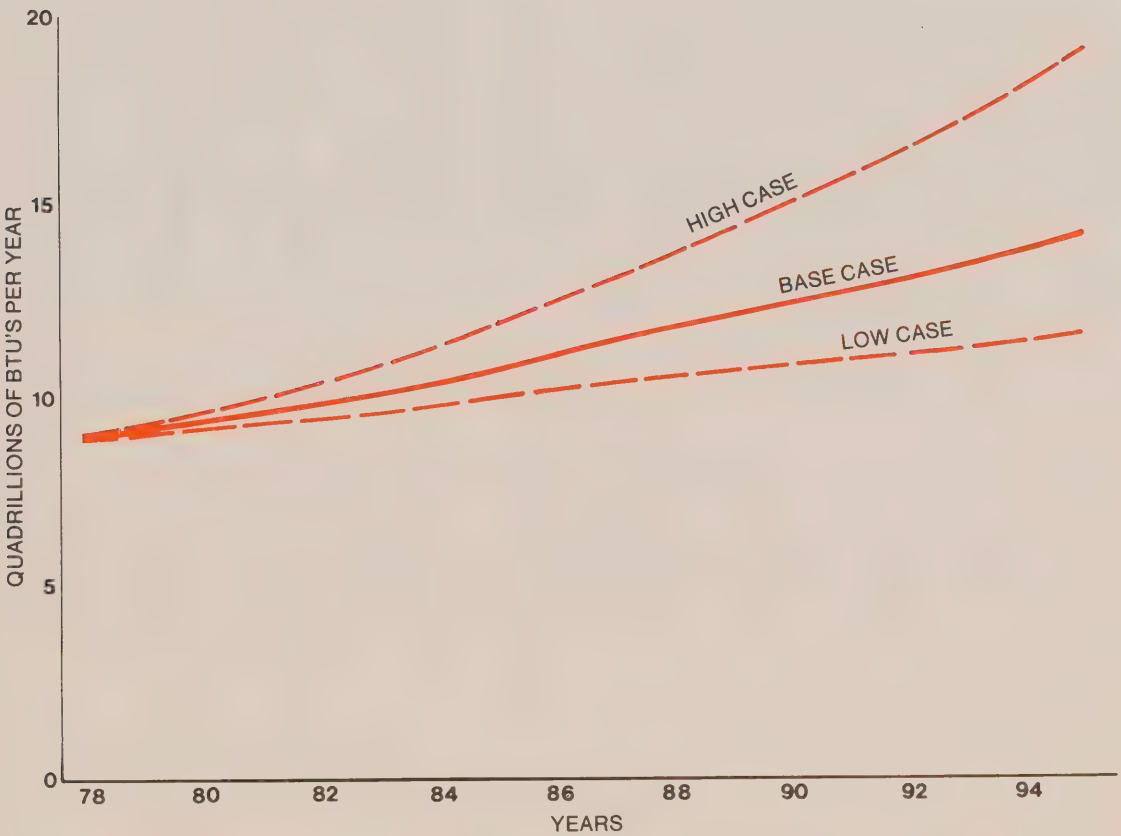


Figure 3-2 **RANGE OF PRIMARY ENERGY DEMAND SCENARIOS**
NEB Forecast

Table 3-11 depicts the Board's projections of total primary energy demand for the high and low demand cases as well as the base case. (See also Figure 3-2)

Table 3-11

PRIMARY ENERGY DEMAND IN CANADA

NEB Scenarios

(Quads)

	1985	1995
High Demand Case	12.0	19.0
Base Case	10.8	14.3
Low Demand Case	10.0	11.7

Although these numbers are very aggregate, they give an overview of the sensitivity of the energy demand forecast to the major input assumptions. In summary, it is the Board's estimate that by 1985 total primary energy demand in Canada could be 11 percent higher or 7 percent lower than the Board's base case, depending on conditions affecting the major determinants of that demand. Appropriately, by 1995 the range of possible demand is significantly larger, with the high demand case being about 33 percent higher than the base case, and the low demand case being approximately 18 percent lower.

CHAPTER 4

DEMAND FOR REFINED PETROLEUM PRODUCTS

4.1 INTRODUCTION

While the previous Chapter discussed the total energy demand forecast and the underlying factors used in its development, this Chapter of the report is concerned with outlining the main considerations involved in translating the forecasts of energy and oil demand, by sector of consumption, into forecasts of demand for individual categories of refined petroleum products.

In the following discussion, the views of the submittors, as well as the views of the Board, are presented for each of the main petroleum product categories, namely:

- motor gasoline;
- light fuel oil, kerosene, and stove oil;
- diesel fuel oil;
- heavy fuel oil;
- petrochemical feedstocks;
- other products.

The review of the demand for each of these petroleum products is accompanied by a graph comparing the forecasts of demand for Canada as a whole provided by submittors, with the base-case forecast of the Board. This Chapter begins with an overview of refined petroleum product demand, and a graph comparing individual forecasts of total net sales (Figure 4-1). For further comparison, Table 4-1 presents the net sales volumes for the main products and the percentage of total net sales that these volumes comprise, and Table 4-2 presents the growth rates of net sales of refined petroleum products.

The Board's forecast of petroleum product requirements by market sector is shown in Appendix H. The forecast of petroleum product demand, by region, is summarized in Appendix I. In addition, for purposes of comparison with submittors on a regional basis, tables are provided in Appendix J.

4.2 OVERVIEW OF DEMAND FOR REFINED PETROLEUM PRODUCTS

4.2.1 Views of Submittors

The views of the submittors reflected the expectation of lower rates of growth in petroleum product demand than previously expected. Accordingly, the forecasts provided by Gulf, Imperial, Shell, and Texaco for this inquiry were lower than the forecasts they submitted to the Board at its previous oil supply and requirements hearing in 1976. For 1995, the final year of the forecast period, the reduction in their current forecasts for total products, compared with their previous forecasts, ranged from about 7 percent for Shell to more than 28 percent for Texaco. Reductions from the submittors' previous forecasts were even greater for individual products running as much as 50 percent for heavy fuel oil. The four submittors mentioned above were the only ones to provide a detailed forecast of demand for all the main refined petroleum products for all the regions in Canada.

Key factors underlying the lower projections of energy demand and the anticipated requirements for petroleum products included lower rates of economic growth, higher energy prices, a greater impact attributable to conservation initiatives, and the effect of interfuel competition. The growth rates implied by the forecasts of the submittors and the Board are compared in Table 4-2.

The submittors' estimates of total refined petroleum product demand ranged between 1754 Mb/d and 1933 Mb/d for 1985 and between 1962 Mb/d and 2220 Mb/d for 1995. As the graphs in the following sections of this Chapter show, the submittors made widely different demand forecasts for the main petroleum products, apart from motor gasoline, but none of the submittors was consistently the highest or the lowest for all products. As noted previously, the forecasts by main product category are compared on Table 4-1, while Figure 4-1 compares the total product forecasts of the submittors.

With respect to motor gasoline demand, there was overall agreement among Gulf, Imperial, Shell, and Texaco that demand would increase slightly until 1980, then decrease for the remainder of the forecast period. Projected volumes were all quite close, as indicated by the graph in Figure 4-2.

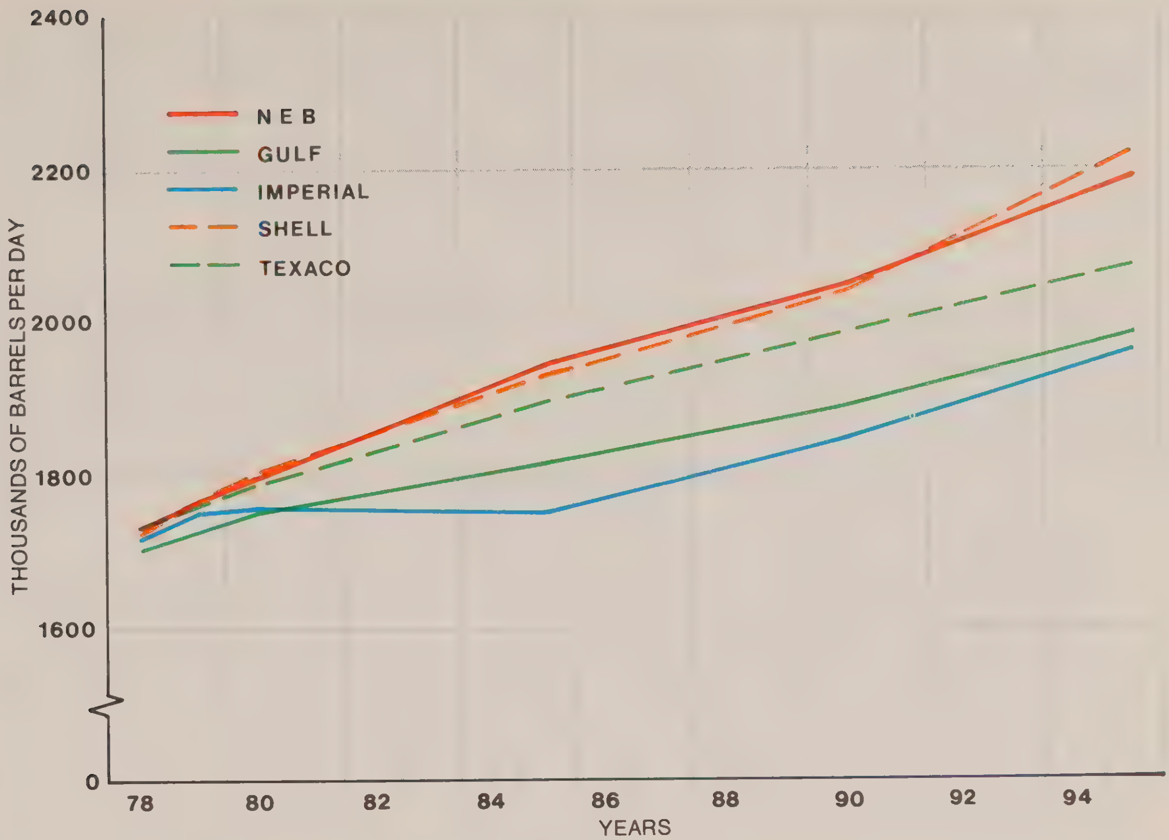


Figure 4-1 **TOTAL PETROLEUM PRODUCT SALES**
Comparison of Forecasts

All submittors indicated a weakening demand for heating oils. Total Canadian demand for light fuel oil, kerosene, and stove oil was projected by Gulf, Imperial, and Texaco to decline steadily throughout the forecast period. Shell projected that demand would decline until 1980 and from then until 1985 would remain constant. Beginning in 1985, demand was forecast to decline slightly, before rising to previous levels by 1995, as a result of an assumed improvement in industrial activity.

Demand for diesel fuel oil over the forecast period was predicted by the four major oil companies to continue to grow at relatively high rates, ranging between 3.4 percent and 4.5 percent for Canada overall. This increase in diesel fuel volumes, coupled with the expected decrease in motor gasoline demand, results in a significant change in petroleum product mix from gasoline to middle distillates.

Because of different assumptions, there was a variance in growth patterns indicated by the submittors with respect to heavy fuel oil demand. Gulf forecast a constant volume from 1978 to 1980, a slight decrease to 1985, and approximately 1 percent annual growth thereafter. Imperial indicated relatively strong growth to 1980, a significant decline to 1985, followed by a resumption of slight growth to the end of the forecast period. Texaco indicated a continuing pattern of growth throughout, averaging less than 1 percent per year. In its submission, Shell had originally forecast heavy fuel oil volumes at levels considerably higher than those of the other submittors. In supplementary material filed after the hearing, these volumes were adjusted downward, primarily to reflect lower requirements for thermal electric generation in Ontario and the Atlantic region, as well as to reflect a lower 1977 base for the Atlantic provinces, and some substitution of heavy fuel oil by hog fuel in British Columbia. After these adjustments, Shell's forecast still remained the highest of the four majors.

Projections of demand for petrochemical feedstocks for all of Canada were provided not only by Gulf, Imperial, Shell, and Texaco, but also by Petrosar, DuPont, and Union Carbide. For the year 1995, estimates ranged between 125 Mb/d (by Gulf) and 196 Mb/d (by Union Carbide-"balanced trade case"). The variation in estimates was the result of different assumptions regarding specific plants or plant expansions, the timing of such occurrences, and different assumptions regarding the growth in demand for derivative petrochemicals.

For the "other products" category, submittors indicated a continuing, but declining growth over the forecast period. Average annual growth rates implied by the forecasts of the four major oil companies ranged between 2.6 percent and 3.3 percent. Some submittors provided specific information with respect to the two major products in this group, namely, aviation fuel and asphalt.

4.2.2 Views of the Board

The Board's forecast of total refined petroleum product demand in Canada indicates an average annual growth rate of 1.4 percent over the 1978-1995 period. This forecast is compared with that of the submittors in the tables and figures referred to previously in this Chapter.

Following analysis of the evidence received, the Board expects that the growth in demand will gradually slacken during the forecast period, as a result of increasing energy prices, lower growth in the economy, interfuel substitution, and the effects of energy conservation measures. However, during the last five years of the forecast period, growth in demand increases slightly, partly as a result of the fact that most of the probable conservation savings have been achieved, i.e., higher real energy prices and other conservation measures are assumed to have had most of their impact by 1990.

The demand for motor gasoline is expected to increase until 1980, but at a rate considerably lower than the average rate of growth experienced in the past ten years. After 1980, demand is expected to decline throughout the forecast period. This slowing down and subsequent decline in the demand for motor gasoline are mainly the result of major improvements in fuel economies, the trend to smaller cars, consumer response to price increases, and some substitution of diesel fuel for gasoline in new automobiles and trucks.

TABLE 4-1

REFINED PETROLEUM PRODUCTS NET SALES TOTAL CANADA

Comparison of Forecasts

Thousands of Barrels Per Day

	Gulf		Imperial		Shell		Texaco		NEB Forecast	
	Net Sales	% of Total Sales	Net Sales	% of Total Sales	Net Sales	% of Total Sales	Net Sales	% of Total Sales	Net Sales	% of Total Sales
Motor Gasoline										
1978	632	37.1	620	36.1	631	36.6	625	36.0	641	37.0
1980	652	37.2	628	35.7	650	36.1	639	35.8	652	36.3
1985	645	35.6	602	34.3	634	32.8	636	33.5	638	32.8
1995	604	30.4	583	29.7	588	26.5	599	29.0	601	27.4
Light Fuel Oil, Kerosene & Stove Oil										
1978	289	17.0	286	16.7	305	17.7	293	16.9	294	17.0
1980	269	15.3	268	15.2	299	16.6	279	15.6	281	15.6
1985	232	12.8	218	12.4	299	15.5	262	13.8	270	13.9
1995	196	9.9	156	8.0	299	13.5	241	11.6	265	12.1
Diesel Fuel Oil										
1978	218	12.8	218	12.7	222	12.9	222	12.8	215	12.4
1980	233	13.3	237	13.5	250	13.9	243	13.6	231	12.9
1985	298	16.5	291	16.6	317	16.4	293	15.4	283	14.6
1995	443	22.3	415	21.2	471	21.2	392	18.9	419	19.1
Heavy Fuel Oil										
1978	302	17.8	296	17.2	286	16.6	294	17.0	295	17.0
1980	302	17.2	314	17.9	294	16.3	300	16.8	311	17.3
1985	300	16.5	283	16.1	331	17.1	310	16.3	333	17.1
1995	334	16.8	304	15.5	392	17.7	336	16.2	367	16.8
Total Refined Products										
1978	1701	-	1717	-	1726	-	1734	-	1734	-
1980	1754	-	1758	-	1801	-	1787	-	1797	-
1985	1813	-	1754	-	1933	-	1897	-	1945	-
1995	1985	-	1962	-	2220	-	2069	-	2190	-

Table 4-2

REFINED PETROLEUM PRODUCTS NET SALES
GROWTH RATES

Comparison of Forecasts

(percent per annum)

	Gulf	Imperial	Shell	Texaco	NEB
1978-1980	1.6	1.2	2.1	1.5	1.7
1980-1995	0.8	1.0	1.4	1.0	1.3

The demand for light fuel oil, kerosene, and stove oil is expected to decline throughout the entire forecast period. Currently, approximately three-quarters of this demand is for use in the residential sector, but this is expected to drop to about two-thirds by 1995. This decrease is expected to occur primarily as a result of higher energy prices, conservation programs, improvements in efficiencies of home oil heating equipment, as well as increased market penetration by natural gas and electricity. In the commercial and industrial sectors, slow growth in the demand for light fuel oil, kerosene, and stove oil is forecast to continue over the forecast period, offsetting for the most part the decline in residential demand after 1985.

Diesel fuel oil demand is projected to increase at a relatively high rate. The Board's estimate of growth in the total demand for diesel fuel oil is influenced to a large degree by its projections of demand for road consumption of diesel fuel, which is expected to experience the highest rate of growth of all sectors using diesel fuel. The Board's estimates of diesel demand reflect its assumptions regarding the growth in real domestic product, substitution of diesel fuel oil for motor gasoline in automobiles and trucks, and a lesser degree of potential energy conservation in comparison with motor gasoline savings. The projected decrease in motor gasoline use and the increase in the consumption of diesel fuel result in a pronounced shift in product mix from gasoline to middle distillates.

Heavy fuel oil demand is expected to show only limited growth over the forecast period. Major contributing factors to lower growth are higher energy prices, lower expected growth in industrial economic activity, and some loss of market share to electricity in both the industrial and commercial sectors in some regions. In preparing its forecast of heavy fuel oil, the Board took into account the evidence regarding expected conversions to hog fuel, i.e., wood waste, in the pulp and paper industry. The Board's forecast of heavy fuel oil demand also reflects reduced requirements for electricity generation, since the demand for electricity is now expected to grow at slower rates than previous forecasts had indicated.

The Board's forecast of petrochemical feedstock requirements is essentially based on projected increases in Ontario, Quebec, and Alberta. The forecast incorporates the expected requirements for Petrosar in Ontario, as well as for expected additional ethylene capacity. A benzene plant using pentanes plus is assumed to come on stream in Alberta.

The total demand for other products is expected to increase at an average annual rate of approximately 3.3 percent from 1978 to 1995. This growth is primarily influenced by aviation turbo fuel and asphalt, which are the two major components in this category, and which are expected to display the strongest rates of growth of all products in this group.

4.3. MOTOR GASOLINE

4.3.1 Views of Submittors

The submittors forecasts of the demand for motor gasoline are compared graphically with the Board's forecast in Figure 4-2.

Forecasts of total Canadian demand for gasoline were provided by Gulf, Imperial, Shell, and Texaco. All predicted a moderate increase in motor gasoline demand until 1980, declining thereafter. Imperial predicted a particularly strong decline over the 1980 to 1990 period.

The submittors forecasts were generally based on assumptions regarding the rate of increase in passenger car registrations, average mileage travelled per car, and fuel economies. Gulf and Texaco also assumed that further tax measures to increase the price of gasoline and to penalize heavy cars would be introduced.

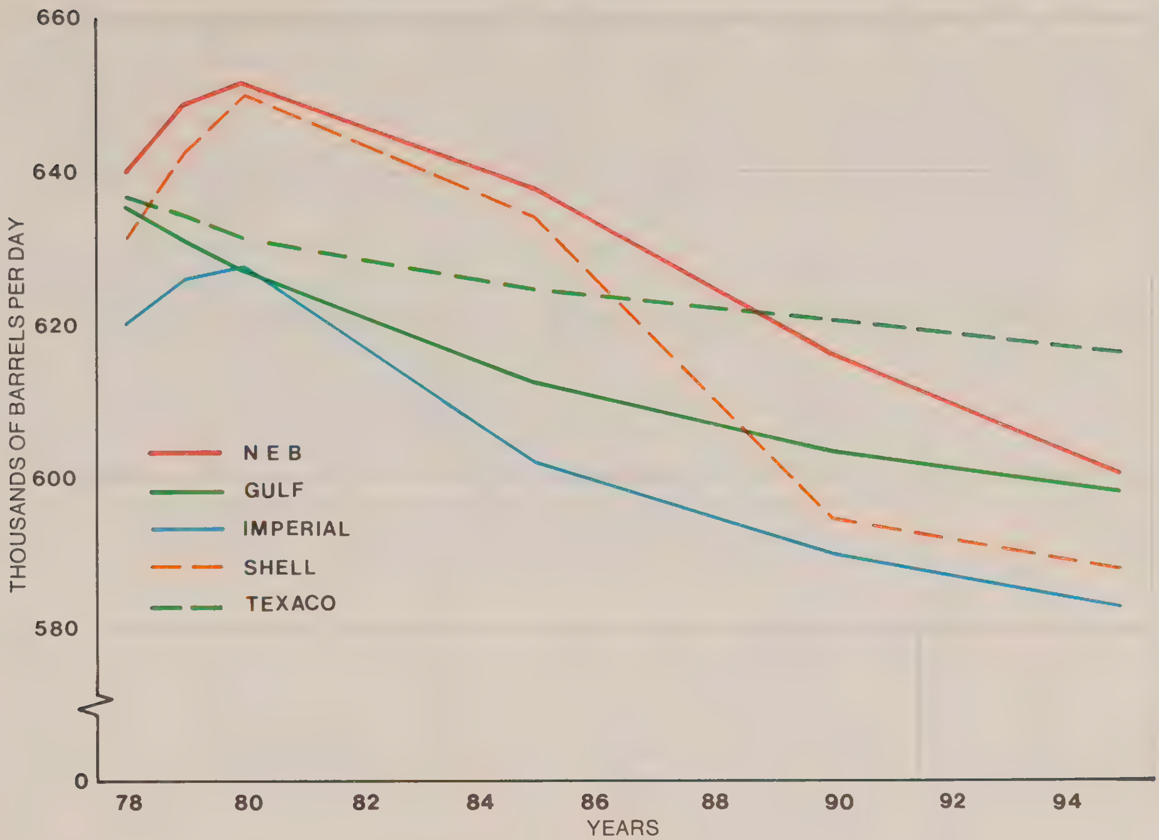


Figure 4-2 **MOTOR GASOLINE**
Comparison of Forecasts

The proportion of total gasoline consumed by trucks and buses was expected to increase. Reasons for this included expectations that an increasing proportion of passenger cars would be diesel-powered and that truck fuel efficiencies would not increase by the same degree as automobile fuel efficiencies.

Sun Oil submitted forecasts of motor gasoline demand for Ontario and Quebec under two cases: the base case and the additional conservation case. The base-case forecast assumed achievement of fuel economy standards and an increasing trend, especially after 1980, to smaller cars. It also included the effects of conservation resulting from price increases and government action. Motor gasoline demand in Ontario and Quebec was estimated to increase from 374 Mb/d in 1978 to 388 Mb/d in 1980, after which demand was forecast to decrease gradually to 365 Mb/d in 1995. The additional conservation case included further modest saving of about five percent resulting from increased use of public transportation and substitution of diesel fuel, methanol, and other fuels for gasoline.

The British Columbia Energy Commission estimated that motor gasoline demand in British Columbia would increase from 67.1 Mb/d in 1978 to 82.4 Mb/d in 1995, at an average annual rate of growth of 1.2 percent. The forecast assumed the achievement of federal mileage standards and substitution of diesel fuel for gasoline in trucks and automobiles.

The Province of Nova Scotia provided forecasts of motor gasoline demand for the Atlantic region under different scenarios. Demand under the base case was estimated to remain essentially constant at 52 Mb/d until 1980, after which it was projected to decline gradually to 45 Mb/d by 1995. The forecast was derived by applying growth rates estimated for Nova Scotia demand to the Atlantic Provinces as a whole. The forecast of demand in Nova Scotia was based on projections of the number of passenger and commercial vehicles, improved fuel economies, and substitution of diesel fuel for gasoline.

4.3.2 Views of the Board

The Board's forecast is based upon a model of passenger car gasoline demand combined with an equation to forecast gasoline used by vehicles other than passenger automobiles. The passenger car gasoline model estimates gasoline consumed by passenger automobiles using forecasts of total population, driver age population, real personal disposable income, unemployment rate, average automobile and gasoline prices, the ratio of prices of small and large cars, the proportion of urban mileage in total mileage, and fuel economies of small and large cars.

Gasoline used by vehicles other than automobiles and for miscellaneous other uses is estimated with an equation that uses forecasts of real domestic product and gasoline prices. Such consumption is mainly accounted for by trucks and buses and will, hereafter, be referred to as truck consumption of gasoline. Estimates based on the gasoline model show that there are significant provincial differences in the current proportion of truck consumption of gasoline. In 1975, the proportion ranged from 52 percent and 47 percent in Saskatchewan and Alberta respectively, to about 23 percent in Ontario and Quebec. The proportion for Canada as a whole was estimated to be 31 percent.

In the passenger car gasoline demand model, the weighted average fuel economy (miles per gallon) per unit of new car sales is determined by the fuel economies of small and large cars combined with their market shares in total new car sales. In examining the historical period, market shares of

different automobiles were defined in terms of weight classes. Market shares over the forecast period, however, describe fuel economy classes. Although there is no precise relationship between weight and fuel economy, weight is by far the most important determinant of fuel efficiency in terms of passenger miles. The terms "small" and "large" as applied to the forecast of car sales, describe automobiles with high and low fuel economies. It is assumed that over the period 1976-1985, fuel economies under road conditions will increase as illustrated in Table 4-3.

Table 4-3

NEW CAR FUEL ECONOMIES BY CAR TYPE

NEB Forecast

(Miles per Imperial Gallon)

	Small Cars		Large Cars	
Year	City	Other	City	Other
1976	19.7	25.4	12.7	16.1
1980	24.4	31.5	15.9	20.1
1985	33.5	43.2	20.7	26.2
1995	33.5	43.2	20.7	26.2

The share of small cars in total new car sales for Canada as a whole is estimated to increase from 37 percent in 1976 to 49 percent in 1985 and to 53 percent in 1995.

Fuel economies assumed in Table 4-3 combined with market shares of small and large cars imply sales-weighted fuel economies under road conditions of about 22 miles per Imperial gallon in 1980 and 30 miles per Imperial gallon in 1985. These fuel economies are lower than the standards set by the Minister of Energy, Mines and Resources that require that under test conditions manufacturer's new car fleets average 24 miles per gallon by 1980 and 33 miles per gallon by 1985. The shortfall in the achievement of federal standards reflects the difference between mileage achieved under test conditions and actual road use.

On the basis of the forecasts of population and number of automobiles on the road, it is estimated that the ratio of persons per car will decline from 2.56 in 1976 to 2.2 in 1985 and then stablize at about 2 persons per car by 1990. The average number of miles travelled per automobile is estimated to decline gradually from 9400 miles in 1976 to about 9000 miles by 1995.

The proportion of urban mileage is assumed to be about 60 percent for small cars and 61 percent for large cars in provinces outside British Columbia. For British Columbia, the proportions are assumed to be 67 percent and 68 percent respectively.

Motor gasoline demand by automobiles and other vehicles is estimated to increase at an average annual rate of 1.7 percent during the 1976-80 period, which is considerably lower than the average annual rate of 5 percent observed during 1966-76. The lower rate of growth during the period until 1980 is attributable partly to the effect of higher gasoline prices and partly to the effect of greater fuel efficiencies of new automobiles.

Between 1980 and 1985, motor gasoline demand is forecast to decline at an average annual rate of about 0.5 percent, and between 1985 and 1995 at a rate of 0.6 percent. The declining trend in gasoline consumption after 1980 is explained mainly by the predominance of more fuel-efficient automobiles and trucks in the total vehicle stock and substitution of diesel fuel for gasoline in new automobiles and trucks. It is assumed that the proportion of diesel-powered automobiles and trucks in total new-vehicle sales will increase from 6 percent in 1985 to 9 percent in 1990 and 13 percent in 1995.

The potential for improving automobile efficiency is assumed to be higher than that for improving truck efficiency. For trucks, the opportunities for improvement in fuel efficiencies are limited primarily to light-duty vehicles. It is assumed, therefore, that over the forecast period, truck fuel efficiencies will increase at a much slower rate than automobile fuel efficiencies. As a result of these differential trends, the proportion of truck consumption of gasoline in total gasoline consumption is estimated to increase from 31.5 percent in 1975 to about 40 percent by 1995.

When compared with the forecast reported in the 1977 Oil Report, the Board's current forecast of motor gasoline demand is lower by two percent in 1980 and five percent in 1995. To a large extent, the slightly lower gasoline demand forecast reflects lower forecast growth in real disposable income and higher assumed substitution of diesel fuel for gasoline in automobiles and trucks. The Board notes that if gasoline prices were about six cents per gallon lower over the forecast period than projected in the base case, forecast demand for gasoline could be, on average, about three and one-half percent higher.

4.4 LIGHT FUEL OIL, KEROSENE, AND STOVE OIL

4.4.1 Views of Submittors

The submittors' forecasts of demand for light fuel oil, kerosene, and stove oil are compared graphically in Figure 4-3.

Gulf, Imperial, and Texaco forecast that the demand for heating oil would decline steadily throughout the forecast period as the result of the effects of energy conservation and conversion to other energy sources. Their forecasts of heating oil demand were all significantly lower than their 1976 submissions; Gulf being 46 percent lower for 1995; Imperial 50 percent lower; and Texaco 55 percent below its 1976 submission.

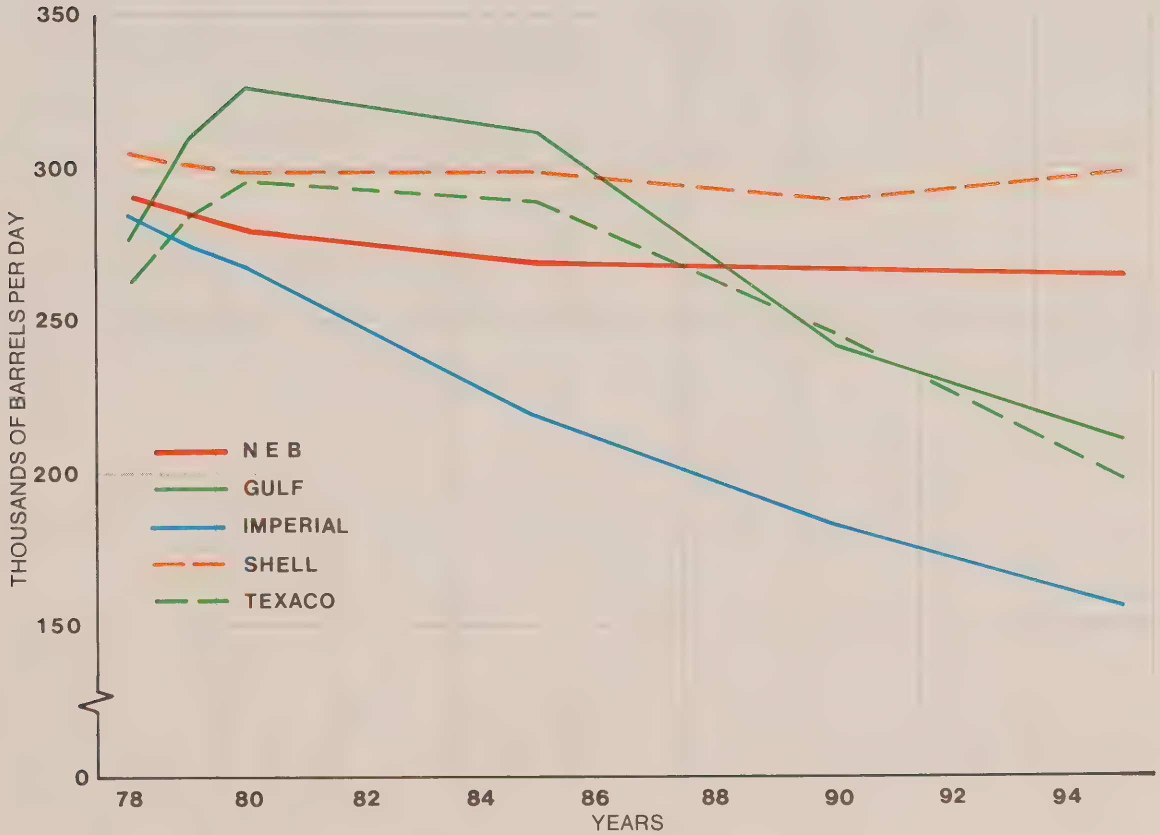


Figure 4-3 **LIGHT FUEL OIL, KEROSENE, AND STOVE OIL Comparison of Forecasts**

Shell expected that overall demand for heating fuels would remain relatively stable throughout the forecast period, declining slightly through 1990 and rising again to 1980 levels by 1995. Shell predicted decreases in the residential sector that would be partly offset by rising demand in the industrial sector as the economy improves. Compared with its 1976 submission, Shell has reduced its forecast for 1995 by approximately 15 percent.

Sun Oil forecast a slight, yet steady decrease in demand for heating oil in Ontario and Quebec. Sun Oil projected a decline in demand for heating oil in Ontario at an average annual rate of 0.5 percent to 1980 and at 0.2 percent from 1981 to 1985. Thereafter, it expected a levelling off of demand. In Quebec, Sun Oil forecast that heating oil demand would decline at an average annual rate of 0.5 percent from 1979 to 1985 and 0.2 percent from 1986 to 1990. It expected Quebec demand to remain level from 1991 to 1995.

For light fuel oil, the British Columbia Energy Commission forecast steady growth in demand in British Columbia, averaging 1.6 percent annually during the forecast period. Demand for kerosene and stove oil in British Columbia was expected to grow at an average rate of 1.1 percent annually between 1975 and 1995.

The Government of Nova Scotia forecast that the annual demand for heating oils in Nova Scotia would increase by an average 1.07 percent from 1977 to 1980, 1.65 percent from 1980 to 1985, and 0.66 percent from 1985 to 1990, and would decrease by 0.3 percent from 1990 to 1995.

4.4.2 Views of the Board

Light fuel oil is used mainly for space heating purposes, with smaller amounts being used for commercial water heating in small establishments and other applications involving the use of low-pressure boilers or other oil-fired equipment.

The Board's forecast of the demand for light fuel oil, kerosene, and stove oil in Canada shows an average rate of decline of 0.6 percent per year over the 1978 to 1995 period. This decline is more rapid before 1985, mainly as a result of changes in the residential demand for these products.

Higher energy prices are a major factor in reducing residential demand in the period up to 1985. Moreover, continued penetration of the residential market by both natural gas and electricity is expected as a result of relative energy prices, differentials in the capital costs of installed new

heating systems, and consumer preference regarding convenience of use and cleanliness. The share held by light fuel oil, kerosene, and stove oil in the residential market is forecast to decline from 38 percent in 1978 to 23 percent in 1995. Demand for light fuel oil in the residential sector also declines as a result of assumed efficiency improvements of oil home heating systems due to improved maintenance, and to increased efficiency of new oil furnaces. By 1995, there is a 9 percent reduction in residential demand for light fuel and kerosene due to this factor.

In the other two major sectors where light fuel oil, kerosene, and stove oil are consumed, i.e., commercial and industrial, slow growth in demand for these products continues over the forecast period, and after 1985 this is sufficient to offset much of the decline in residential demand. The changes in the distribution by sector of the demand for these products are shown in Table 4-4.

Table 4-4

CONSUMPTION OF LIGHT FUEL OIL, KEROSENE, AND STOVE OIL BY MARKET SECTOR

NEB Forecast

(Percentage)

	1975	1985	1995
Residential	72.3	68.5	65.2
Commercial	14.9	16.0	17.5
Industrial	10.8	13.1	15.2
Other	2.0	2.4	2.1
	100.0	100.0	100.0

Quebec and Ontario are the major consuming regions of light fuel oil, kerosene, and stove oil. In 1975, they accounted for 37.4 percent and 31.5 percent of the total Canadian demand, respectively. The Atlantic region followed with 17.2 percent. In general, the regional behaviour of the major consuming sectors is similar to the overall Canadian sector behaviour discussed previously. The main exception occurs in the residential sector in the Atlantic region. In this case, demand is forecast to remain relatively constant at its 1978 level of 38 Mb/d, rather than declining. Here, the share of the residential sector held by these products is not expected to decline as significantly as in either Quebec or Ontario. Consequently, in the Atlantic region the slow growth in total energy demand in the residential sector is sufficient to offset the decline in market share.

In comparison with the forecast contained in its 1977 Report, the Board's current forecast of the demand for light fuel oil, kerosene, and stove oil is lower by 26 percent by 1995. Analysis of the evidence presented led the Board to conclude that its previous forecast should be reduced. The two main sectors accounting for the drop in demand are the residential and industrial sectors, with the declines amounting to 30 Mb/d and 48 Mb/d respectively in 1995.

In the residential sector, the decrease in demand may be attributed in large part to increased conservation and a lower market share for oil. The lower oil share is expected as a result of the increased penetration by both electricity and renewable energy sources in the present forecast. In the industrial sector, a lower total energy forecast and a lower light fuel oil market share are the main reasons for the decreased demand for these products. Increased electricity penetration of the industrial market is expected as a result of a more developed industrial structure that will utilize electricity more intensively.

4.5 DIESEL FUEL OIL

4.5.1 Views of Submittors

The submittors' forecasts of diesel fuel demand are compared graphically in Figure 4-4.

Those submittors who made forecasts of diesel fuel demand for total Canada - Gulf, Imperial, Shell, and Texaco - all predicted fairly strong rates of growth. The average annual growth rates for diesel fuel demand over the forecast period varied between 3.4 percent and 4.6 percent among these submittors.

Sun Oil projected comparatively slower growth in diesel requirements in Ontario and Quebec due to the expected impact of conservation measures.

The Government of Nova Scotia anticipated a 4.2 percent average annual growth rate in diesel demand for the Province, with marine transportation requirements showing the strongest growth rate.

In 1995, Gulf, Shell, and Texaco projected diesel fuel demand to be, 3.7, 18.3, and 2.3 percent higher respectively than the forecasts submitted to the Board in 1976. These upward revisions basically reflected the expectation of continuing strong growth rates in transportation diesel requirements. On the other hand, Imperial's forecast of diesel demand is 2.4 percent lower in

1995 when compared with the forecast submitted for the previous oil hearing. This is due to the lower economic growth rate underlying Imperial's current projections.

4.5.2 Views of the Board

Diesel fuel oil is consumed primarily in the industrial sector and for road and rail transportation. Smaller quantities are also consumed for marine transportation and in the residential (farm) and commercial sectors.

Total diesel fuel oil demand is estimated to grow at an average annual rate of four percent from 1978 to 1995. It is estimated that among sectors, road consumption of diesel will increase at the highest rate and commercial use of diesel at the lowest. The high rate of growth forecast

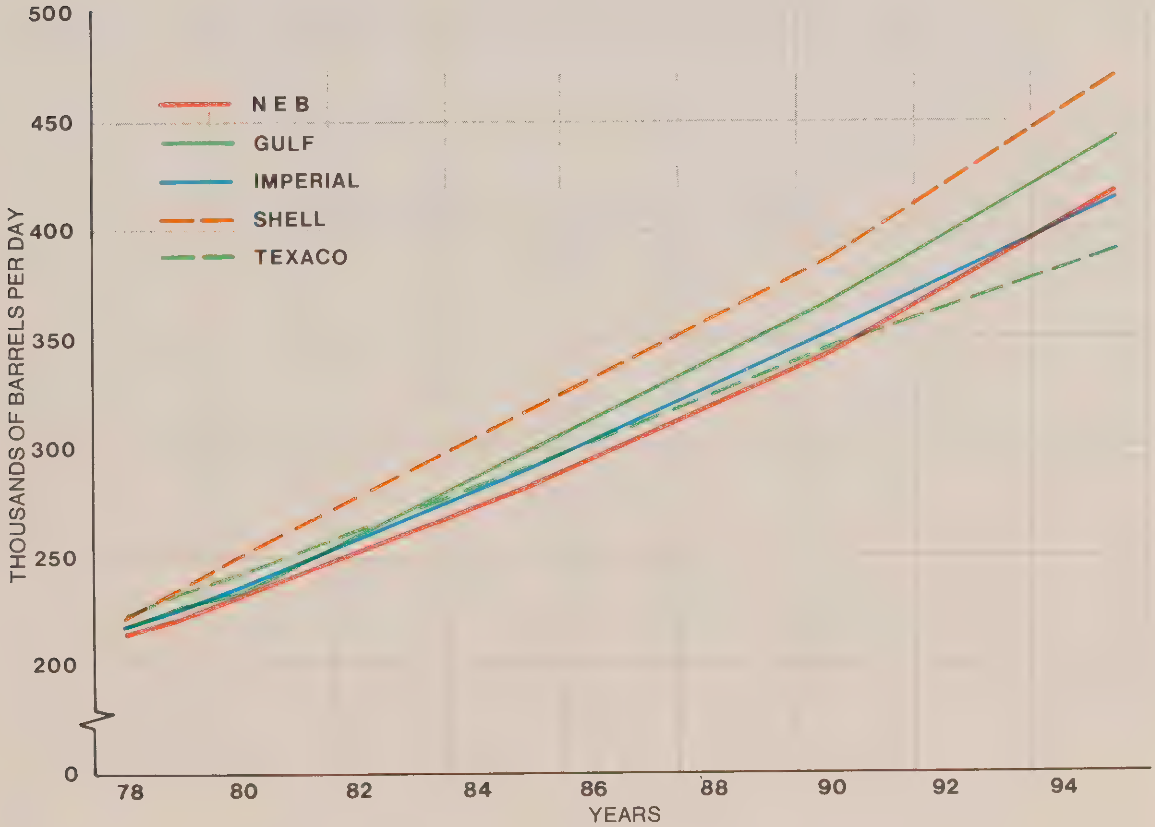


Figure 4-4 **DIESEL FUEL OIL**
Comparison of Forecasts

for road diesel consumption is explained by growth in real domestic product, substitution of diesel fuel for gasoline in automobiles and trucks, and the more-limited potential for conserving diesel fuel through increasing fuel efficiencies compared with motor gasoline. The lower rates of growth in diesel use estimated for other sectors reflect, to a large extent, assumptions regarding conservation in those sectors, as discussed in Chapter 3.

Until 1985, the current forecast of diesel demand is almost identical to that given in the 1977 Oil Supply and Requirements Report. For the period after 1985, the present forecast becomes progressively higher than that in the previous report, becoming 5.2 percent higher in 1990 and 11.7 percent higher in 1995, mainly as a result of higher growth rates forecast for road consumption of diesel.

4.6 HEAVY FUEL OIL

4.6.1 Views of Submittors

The submittors' most-likely forecasts of the demand for heavy fuel oil are shown graphically in Figure 4-5.

The range of submittors' estimates of the demand for heavy fuel diverged in the post-1980 period with Gulf and Texaco forecasting moderate growth, Imperial forecasting a significant decline in the 1980 to 1985 period followed by a resumption of moderate growth, and Shell forecasting stronger growth throughout the period.

Gulf

Gulf expected that conservation efforts would slow growth substantially from historical levels during the first five to ten years of the forecast. In the Atlantic provinces, coal was predicted to displace heavy fuel oil for electricity generation during the early 1980's. Gulf made no allowance for the increased use of hog fuel in the forest industry in place of heavy fuel oil. Gulf's estimated demand in 1995 was nearly 29 percent lower than the estimate provided in its 1976 submission.

Imperial

Imperial predicted lower demand growth, particularly in the 1980 to 1985 period, on the basis of its assumption that the natural gas transmission system would be extended east of Montreal into regions presently without natural gas service. None of the other submittors who forecast total heavy fuel oil demand for Canada made this assumption. Imperial's forecast showed the greatest decline in expected heavy fuel oil demand of all submittors, being 40 percent lower in 1995 than its forecast submitted in 1976.

Shell

Shell expected comparatively strong demand growth on the basis of assumptions that heavy fuel oil would be in a competitive position relative to other fuels in Ontario and Quebec, and that there would not be an expansion in the regions serviced by natural gas. Shell showed even stronger demand growth in its original submission, but modified its projection following the inquiry to reflect lower requirements in Ontario and the Atlantic provinces for heavy fuel oil for thermal power generation and to take into account conversions by companies in British Columbia that would allow them to substitute hog fuel for heavy fuel oil.

Texaco

Texaco predicted steady but moderate growth of heavy fuel oil demand throughout the forecast period. Based on its revised assumptions with regard to economic and population growth late in the forecast period, Texaco's estimate for 1995 was 39 percent lower than in its 1976 submission. It should be noted that in its 1976 submission, Texaco's estimate of heavy fuel oil demand in 1995 was about 10 percent higher than estimates submitted by other participants at that time.

Union Carbide

Union Carbide forecast comparatively strong growth in heavy fuel oil demand throughout the forecast period. It noted that its heavy fuel oil demand forecast was 10 percent to 20 percent below levels forecast in its 1976 submission to the Board, primarily due to changed assumptions with respect to general economic conditions and energy conservation.

BCEC and COFI

In its submission the British Columbia Energy Commission forecast a growth in heavy fuel oil demand of 2.6 percent over the period 1985 to 1995. In its testimony before the Board, the BCEC reduced its fuel oil demand for 1978 and following years, by 2700 barrels per day in order to account for hog fuel projects coming onstream in the forest industry. The British Columbia Council of Forest Industries, as discussed in Chapter 6, also expected further displacement of heavy fuel oil by hog fuel.

Chevron Canada

Chevron Canada estimated heavy fuel oil demand in British Columbia to decline moderately until 1980, then to rise slightly until 1990, when demand stabilizes. Chevron believed the British Columbia heavy fuel oil market was shrinking due largely to alternative energy and conservation projects coming on stream at several coastal pulp mills.

Nova Scotia

Nova Scotia believed that heavy fuel oil demand in that Province would decline by over 5 percent per annum in the 1977 to 1980 period, then rise by about 2.6 percent from 1980 to 1985 and then once again decline by over 3 percent per year from 1985 to 1995.

Ontario Hydro

Ontario Hydro estimated its requirements for heavy fuel oil for its Lennox and Wesleyville generating stations to be between 2 Mb/d and 52 Mb/d for the period up to 1980, and 3 Mb/d to 78 Mb/d thereafter. The most-likely demand was estimated to be in the 3 Mb/d to 14 Mb/d range. The Bruce steam plant was forecast to require 3 Mb/d in 1978 declining to 2 Mb/d for the remainder of the forecast period.

Sun Oil

Sun Oil expected growth rates for heavy fuel oil of 1.5 percent and 2 percent in Ontario and Quebec respectively throughout the forecast period. This compared with its annual growth estimates of 2 percent and 3 percent respectively in its 1976 submission to the Board.

4.6.2 Views of the Board

The Board's forecast of the total Canadian demand for heavy fuel oil is presented in Figure 4-5 along with the forecasts of the submittors. The forecast is also presented tabularly, by region, in Appendix I.

Analysis of the various submissions and testimony makes it clear that total heavy fuel oil demand in Canada will increase quite slowly over the forecast period. Heavy fuel oil is consumed in significant quantities in the commercial, industrial, and marine sectors, as well as in the generation of electricity. It is consumed in significant quantities in all regions except the Prairies. The most important components of the total are discussed hereunder.

Approximately 40 percent of heavy fuel oil consumption in Canada occurs in Quebec. It is forecast that demand in Quebec will grow at 1.9 percent per annum between 1985 and 1995; this is faster than the national average. Over half of heavy fuel oil consumption in Quebec occurs in the industrial sector, where demand is forecast to grow at an average rate of 2.3 percent. Given the total energy

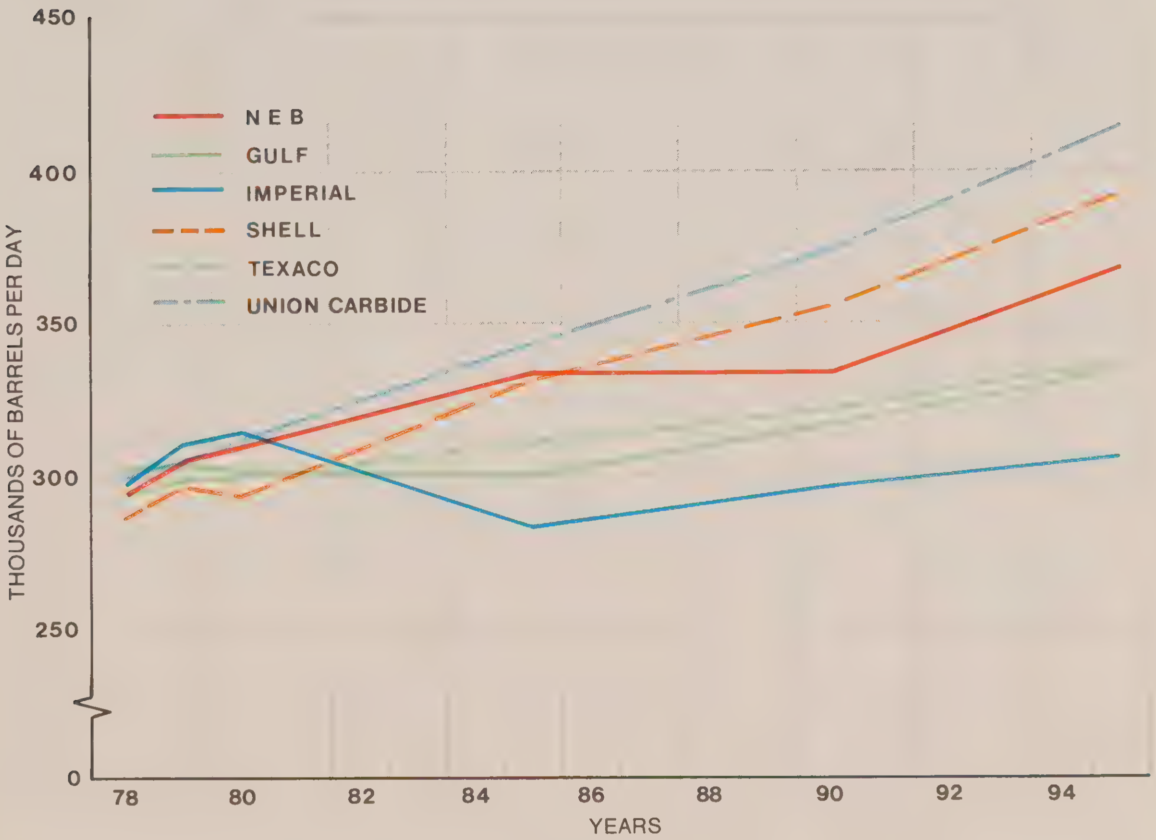


Figure 4-5 **HEAVY FUEL OIL Comparison of Forecasts**

projection for the industrial sector of Quebec (Chapter 3), the heavy fuel oil demand forecast is strongly influenced by two important assumptions. First, it has been assumed for the purposes of this forecast that there will be no expansion of the natural gas service area in Quebec. Second, it is assumed that heavy fuel oil and natural gas will be priced competitively at the burner tip. These assumptions, combined with an analysis of appropriate historical trends, suggest that the market share of heavy fuel oil use in the industrial sector of Quebec will remain reasonably constant over the forecast period, implying that heavy fuel oil will grow at approximately the same rate as total energy. The demands for heavy fuel oil in the marine sector and particularly in the commercial sector are expected to grow quite slowly in Quebec; this is in line with the recent historical experience. Very little heavy fuel oil is consumed in the other sectors in Quebec.

Regionally, the second largest consumer of heavy fuel in Canada is the Atlantic region, where approximately 30 percent of total Canadian consumption takes place. In this region, the major portion of heavy fuel oil is consumed in the generation of electricity. The forecast in this area, which is based on an examination of utility expansion plans, depicts an increase in requirements from approximately 50 Mb/d in 1978 to 54 Mb/d in 1985. Demand is then forecast to decrease to 42 Mb/d by 1990, and then increase slightly to 49 Mb/d in 1995. The expected decrease in requirements from 1985 to 1990 reflects the fact that no provision has been made for exports to the United States of electricity generated from heavy fuel oil at the Colson Cove plant in New Brunswick after 1986 when the current export licence expires. Demand in the industrial sector, which accounts for approximately 25 percent of the total heavy fuel consumption in the Atlantic, is projected to increase at an average annual rate of 2.2 percent. It is expected that the market share of heavy fuel oil in the industrial sector of the Atlantic region will decline slowly over time, as the share of electricity increases. This is consistent with historical trends.

Ontario accounts for approximately 20 percent of heavy fuel oil consumption in Canada. Demand in that Province is forecast to remain essentially constant over the forecast period. Most of the heavy fuel oil consumption is expected to occur in the industrial sector, where the forecast growth in total energy demand is offset by the expectation that the market share of heavy fuel oil will

continue to decline. This declining share is not the result of penetration of gas, since the two energy types are assumed to be priced competitively. Rather, it reflects expected continuing market penetration by electricity as a larger proportion of industrial activity occurs in secondary manufacturing. The demand for heavy fuel oil for electricity generation is forecast to remain at about 9 Mb/d throughout the forecast period, of which approximately 6 Mb/d is expected to be used by utilities. This is consistent with recent projections made by Ontario Hydro.

It will be noted that the present forecast of heavy fuel oil demand is significantly lower than that developed for the 1977 Report. Specifically, the total Canadian heavy fuel oil demand is now expected to be about 25 percent lower in 1995 than was forecast last year. This reduction reflects significant decreases in most sectors and regions. The major contributing factors are discussed below, by sector.

In the industrial sector, heavy fuel oil demand is now forecast to be approximately 14 percent lower by 1995 than was forecast in the 1977 Report. There are several reasons for this decrease. First, somewhat slower growth in industrial economic activity is now being projected. Second, a considerable amount of work of a methodological nature has been done over the last year with a view to improving the total energy forecasts for the industrial sector. The effect of these improvements has been to reduce the total energy demand forecast somewhat. The market share of heavy fuel oil underlying the present forecast is not lower than was projected for the 1977 Oil Report. In fact, through 1985 it is slightly higher in both Ontario and Quebec (and total Canada), which is a reflection of recent historical experience in the large industrial markets of these provinces. Finally, the current forecast of heavy fuel oil demand takes into account evidence presented at the inquiry concerning anticipated conversion to the use of hog fuel in the pulp and paper industry.

The demand for heavy fuel oil in the commercial sector is now projected to be 48 percent lower by 1995 than was projected in the 1977 Report. It is now believed that electricity will penetrate the commercial market at a faster rate than was previously thought, at the expense of heavy fuel oil (and other energy types). Furthermore, recent data indicated that the previous forecast of total energy in the commercial sector was high. This is also the case in the marine sector, where the present forecast of heavy fuel oil demand is about 25 percent lower by 1995 than the previous forecast.

The present forecast of heavy fuel oil requirements for electricity generation is approximately 35 percent lower by 1995 than was the case for the 1977 report. Much of this reduction occurs in Ontario. Ontario Hydro has recently reduced its forecast of electricity demand, which has resulted in reductions in its projected requirements for all energy types for electricity generation. The decrease for heavy fuel oil will be more than proportionate, however, since oil-fired units are expected to be among the first to be cut back. The present NEB forecast is consistent with Ontario Hydro's submission.

4.7 PETROCHEMICAL FEEDSTOCKS

4.7.1 Views of Submittors

The submittors' most-likely forecasts of demand for petrochemical feedstocks are shown graphically in Figure 4-6. The forecasts up to about 1985 were generally based on expectations as to when particular petrochemicals plants would come on stream. After 1985, forecasts were not developed in such a plant-specific manner.

AERCB

The AERCB assumed that 12.8 million barrels of oil per year would be used as feedstock to produce benzene in a plant starting up in 1982, and 12.3 million barrels per year in the production of ethylene and ethylene derivatives commencing in 1995. An ethylene plant was also assumed to be built in the mid-1980's using natural gas and 20 percent propane as a feedstock.

DuPont

DuPont's projection of liquid petrochemical feedstock demand assumed that another liquid-based facility would be needed by 1983. After 1985, DuPont projected a trend line that resulted in a liquid feedstock growth rate of about seven percent to eight percent per year from 1977 to 1995. DuPont believed that the growth rate of the petrochemical industry beyond 1980 could vary considerably depending on the investment climate.

Petrosar

Petrosar based its estimate of liquid petroleum feedstock requirements on its asssessment of future demand for ethylene and butadiene. The assumption made was that by 1980 the quantity of ethylene contained in derivative petrochemicals consumed in Canada will be matched by ethylene produced in Canada, with any imports of derivative products being offset by exports of other derivatives. Approved exports of ethylene (350 million pounds per year) are included in this case.

With respect to butadiene, Petrosar assumed, on the basis of the requirements and export potential identified by Polysar in its submission, that butadiene supply could rise from 260 million pounds in 1978 to 610 million pounds in 1995. This assumed that a new liquid cracker would commence operation in mid-1983 and would be operating at capacity in 1985.

Polysar

Polysar advocated that the Board recognize the potential of another billion-pound increment of liquids-derived ethylene coming on stream in the mid-1980's with a feedstock requirement of 45 Mb/d. Under cross-examination, Polysar did state that an ethane-based ethylene plant in Alberta would meet the ethylene demand in the 1980's, but suggested that before deciding on the merits of an ethane-based or liquid-based facility, one would have to look at a number of factors, some of which would suggest that there would be certain advantages to a liquids cracker. Polysar did not recommend a particular type of facility.

Petalta

Petrochemicals Alberta Project testified that it was awaiting the decision of the Lieutenant-Governor-in-Council with respect to its application to build a benzene plant in Alberta. The project, if approved, could commence in 1982 with an initial requirement of 31.5 Mb/d of pentanes plus in the start-up year, rising to 35 Mb/d for the remaining 19 years of the plant's estimated life. However, Petalta did state that start-up could be delayed until after 1982 as it still had a number of regulatory approvals to obtain.

Quebec

Although it did not forecast petrochemical feedstock demand, Quebec in its supplementary submission made suggestions to assist the Canadian petrochemical industry. Quebec proposed that oil used in petrochemical production should be priced slightly lower than oil used as feedstocks for petrochemicals plants located in the Gulf of Mexico. Furthermore, Quebec suggested that oil used for petrochemical production should be exempt from the surcharge imposed on conventional oil by recent amendments to the Petroleum Administration Act (Bill C-19).

Union Carbide

Union Carbide projected a "Status Quo" case based on the growth rates of the two prime ethylene derivatives, i.e., polyethylene and ethylene oxide, that would result in liquid petrochemical feedstock demand of 151 Mb/d in 1995. However, Union Carbide advocated that a more reasonable growth target for the petrochemical industry would be the "Balanced Trade" case as set out in the sector profile "The Canadian Petrochemical Industry" issued recently by the Chemicals Branch of the Department of Industry, Trade and Commerce. Under this case, petrochemical production in Canada would grow from the present level of two-thirds to three-quarters of domestic consumption to a level equal to domestic demand. Under this scenario, liquid petrochemical feedstock demand could grow to 196 Mb/d.

Union Carbide further estimated that demand for liquid feedstocks in either the "Balanced Trade" or the "Status Quo" cases could increase by as much as 20 percent in the 1990's, which is roughly equivalent to one world-scale olefins unit, as natural gas liquids declined and the petrochemical industry became more mature and integrated.

4.7.2 Views of the Board

The Board's forecast of demand for petrochemical feedstocks is presented graphically in Figure 4-6. Most of the forecast increase in feedstock requirements results from projected increases in Ontario, Quebec, and Alberta. There was no demand for petrochemical feedstocks in Manitoba or Saskatchewan or in the Yukon and the Northwest Territories in 1976 and 1977, and it is therefore assumed that no use of petrochemical feedstocks will be made in these areas during the forecast period. In the Atlantic Provinces and British Columbia, the demand for petrochemical feedstocks is assumed to continue at the 1977 level. The assumptions underlying the demand forecasts are described below.

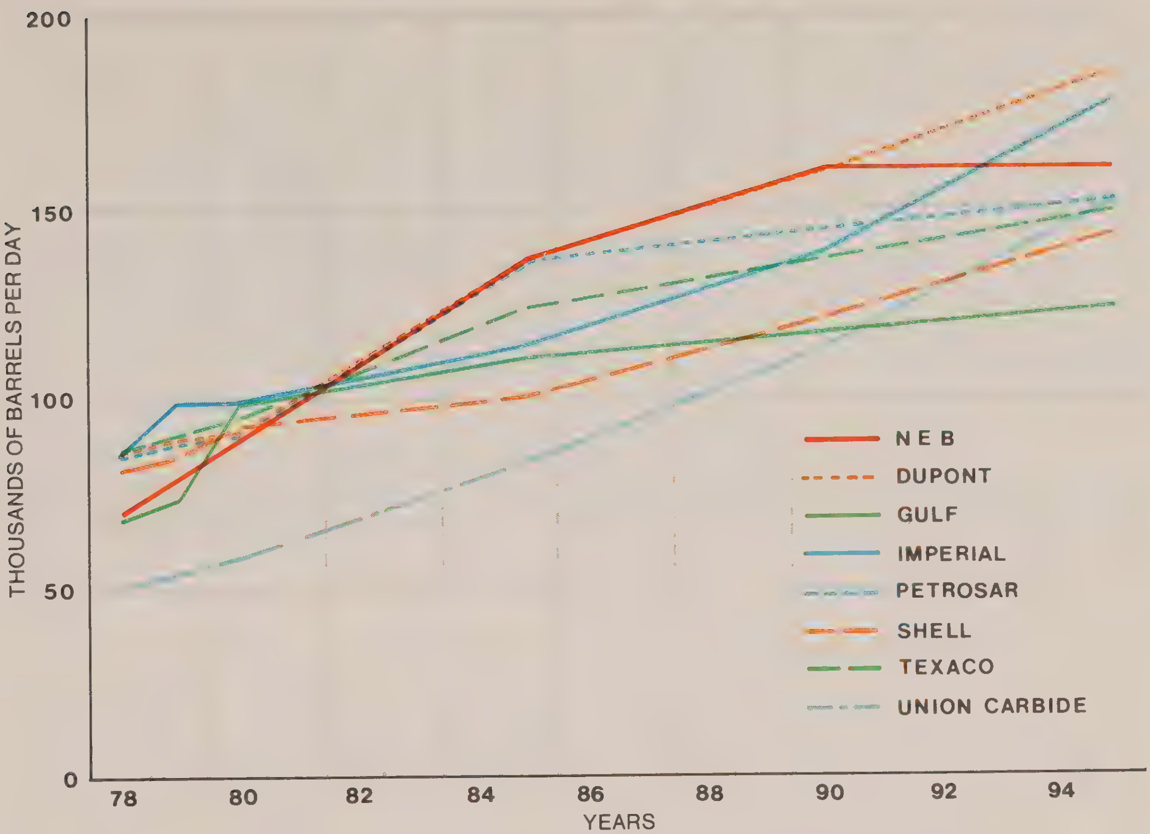


Figure 4-6 **PETROCHEMICAL FEED STOCKS Comparison of Forecasts**

Petrosar commenced operation of its crude unit in March 1977, and of its petrochemical units in November 1977. Based on the evidence submitted by Petrosar at the inquiry, it is assumed that Petrosar's petrochemical unit will reach capacity production in 1980, requiring 45 Mb/d of naphtha feedstock. It is assumed that liquid feedstocks demand by Petrosar during 1978 and 1979 will increase by 27 Mb/d and 36 Mb/d, respectively.

For the period after 1980, it is assumed that ethylene production capacity, based on liquid petrochemical feedstocks, will increase by 640 million pounds in 1985 and by an additional 500 million pounds in 1990. These expansions in capacity will increase demand for liquid feedstocks by approximately 29 Mb/d in 1985 and by an additional 23 Mb/d in 1990. It should be noted that the Board expects that ethylene production capacity will be further increased by an ethane-based plant in Alberta which is assumed to come on stream in 1985. However, since this does not represent a demand for liquid feedstocks, it is not included in the Board's projection of oil demand in this report.

A world-scale benzene plant using pentanes plus as feedstock is assumed to come on stream in Alberta by 1985. The plant is assumed to increase liquid feedstocks demand by 20 Mb/d.

4.8 OTHER PRODUCTS

For purposes of this report, the other-products category consists of refinery-produced propane and propane mixes, butanes, naphtha specialties, aviation gasoline, aviation turbo fuel, asphalt, lubricating oils and greases, and waxes. The submittors' forecasts are compared to the NEB's forecast of demand for other products in Figure 4-7.

4.8.1 Views of Submittors

Gulf, Imperial, Shell, and Texaco provided forecasts of demand for the total of other products, for Canada overall, and these forecasts are compared in Figure 4-7. Other submittors, such as the Province of Nova Scotia and the Government of British Columbia, provided forecasts for their specific regions. These projections are shown in the regional comparison tables in Appendix J. Some submissions included information on the specific products that comprise this product category, namely, aviation fuel and asphalt.

Regarding aviation fuel, Imperial filed supplementary information wherein it was estimated that the demand for turbo fuel would increase at an average annual rate of 3.7 percent between 1978 and 1995. This forecast reflected Imperial's expectation that growth in air travel would keep pace with that of the economy in the forecast period, but it also reflected the expected improvement in operating efficiencies, which were expected to have the greatest impact before the end of 1980.

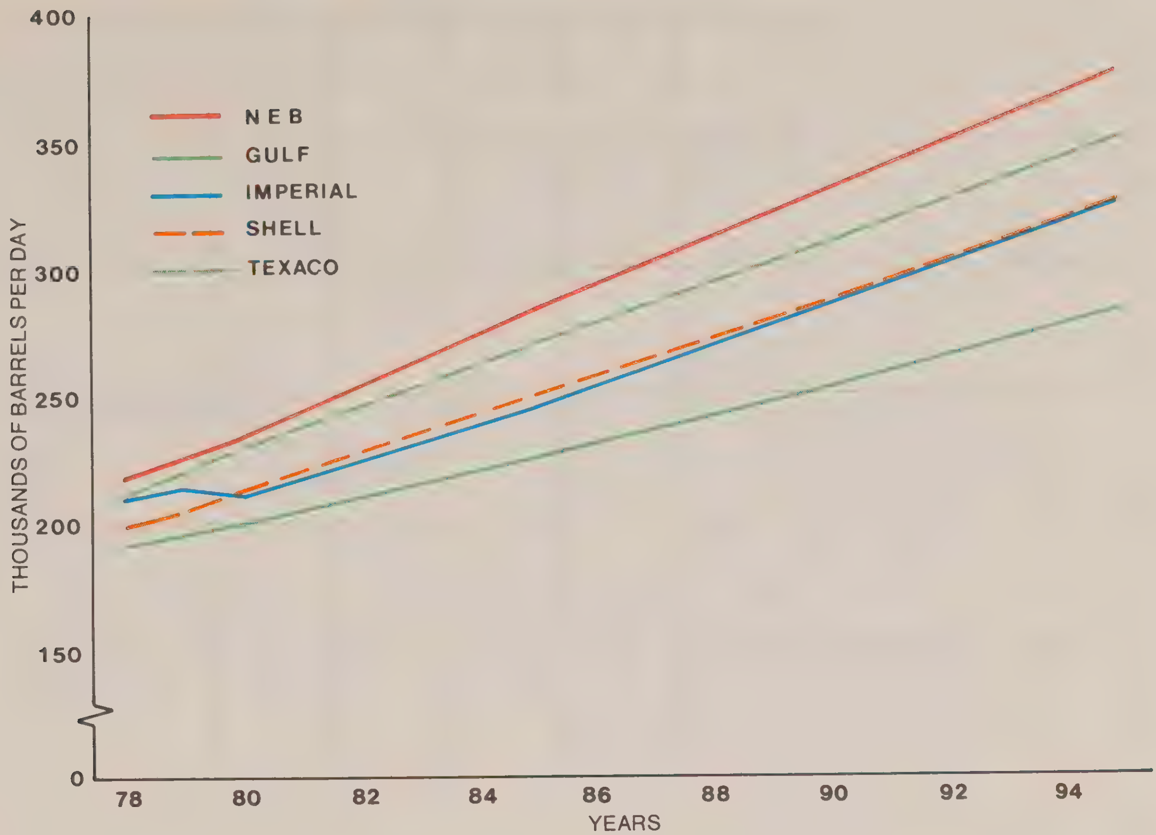


Figure 4-7 **OTHER PRODUCTS Comparison of Forecasts**

Shell did not provide a forecast of aviation fuel, but stated that growth in the sector was expected to average 2.9 percent through 1985, and 2.6 percent until 1995. Gulf indicated that aviation turbo fuel was expected to grow at rates considerably below historical levels to reflect the targets for improved efficiency adopted by the major airlines. Gulf did not, however, provide specific growth rates.

Regarding asphalt demand, there was some variation with respect to expected rates of growth. Although no submittor provided a specific asphalt forecast for total Canada, some estimates of anticipated growth were provided. Shell indicated an expected growth of 3 percent per annum, while Husky was higher at 3.5 percent.

On a regional basis, PanCanadian and Ashland provided forecasts of asphalt demand for the Prairies, Ontario, and Quebec. These combined regions were expected to experience an average annual increase of 1.3 percent. The PanCanadian and Ashland forecasts were identical, since they were both based on a study of heavy crude markets conducted by Hycarb Engineering Ltd. Nova Scotia estimated that after 1979 use of asphalt would increase by 2 percent per year for that Province.

4.8.2 Views of the Board

As illustrated in Figure 4-7 and in Appendix I, the overall demand for other products is expected to increase at an average annual growth rate of 3.3 percent over the forecast period.

Aviation turbo fuel and asphalt are the two major components in the other products category, comprising respectively approximately 37 percent and 27 percent of the product volume of this category in 1977. These two products are expected to experience the strongest rate of growth of all the products in this category.

The Board's forecast of demand for aviation turbo fuel shows an increase from 70 Mb/d in 1978 to 148 Mb/d in 1995. This represents an average annual growth rate of 4.5 percent over the entire forecast period. This is considerably below historical levels and reflects the effects of energy conservation initiatives in the aviation sector. The Board expects that the annual rate of increase for the last ten years of this period will be reduced to 3.3 percent. Few submittors provided specific information with respect to aviation turbo fuel, but it is noted that the Board's forecast is consistent with their expectations that growth in demand for this product will diminish.

The demand for asphalt is projected to grow at an average annual rate of 3.6 percent increasing from 55 Mb/d in 1978 to 99 Mb/d in 1995. Growth is expected to be more rapid over the earlier part of the forecast period, and to slow down to an average of 3.2 percent during the last ten years.

4.9 POTENTIAL RANGE OF PETROLEUM PRODUCT DEMAND

In addition to developing a base case of oil demand, the Board has developed high and low demand cases. The general rationale and description of these scenarios have been discussed in Section 3.5 of the Report. The emphasis in that Section was on total primary energy. A summary of the results for refined petroleum products is given in Table 4-5.

Table 4-5

NET SALES OF REFINED PETROLEUM PRODUCTS

Range of Scenarios

NEB Forecast

(Mb/d)

	1985	1995
High Demand Case	2153	2794
Base Case	1945	2190
Low Demand Case	1794	1949

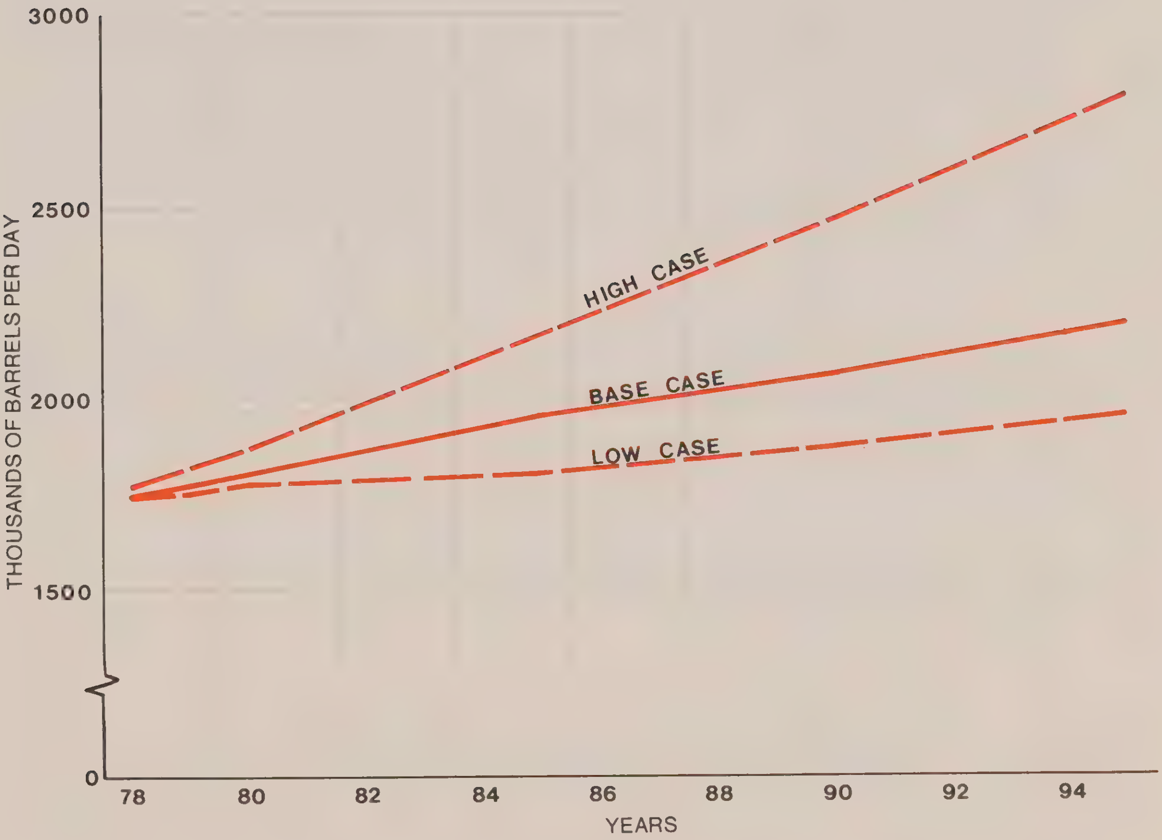


Figure 4-8 **NET SALES OF REFINED PETROLEUM PRODUCTS Range of Scenarios NEB Forecast**

It is the Board's estimate that net sales of refined petroleum products could be about 11 percent higher or 8 percent lower than the Board's base case in 1985, rising to 26 percent higher or 11 percent lower in 1995, depending on the assumptions made regarding the major determinants of the demand. It might be noted that the range of possible estimates differs by refined petroleum product and, to a lesser extent, by region. This is because consumer responsiveness to energy prices and the effects of economic and demographic variables differs for each refined product, market sector, and region. The different levels of oil demand under the different scenarios do not reflect different degrees of interfuel substitution. Relative burner-tip energy prices are assumed to be the same in all three cases.

A graph comparing petroleum product net sales under the different scenarios is provided in Figure 4-8.

4.10 EXPORT FORMULA CASE

As outlined in its previous reports on oil supply and requirements, the Board has been using a formula to determine the levels of crude oil exports that would be appropriate given the goal of providing protection for Canadian requirements. The formula requires that estimates be made of the quantitative impact of conservation. The annual savings resulting from these programs are taken into account when calculating allowable exports.

Preceding sections of this report are concerned with estimates of the most-likely level of energy demand. By definition, those forecasts take into account reductions in demand resulting from price increases after 1972, and various existing and expected conservation programs. For purposes of the export formula, it is necessary to estimate the levels that energy demand would reach if prices remained at 1972 levels and if conservation programs had not been adopted. The Board's estimate of demand under this no-conservation assumption is identified here and elsewhere in this report as the "Export Formula" case.

The results of this scenario are summarized, for total energy and for total oil, by market sector in Appendix H. For purposes of comparison with the Board's base-case forecast, total product estimates for the export formula case are shown in Appendix I.

CHAPTER 5

REQUIREMENTS FOR FEEDSTOCKS

5.1 INTRODUCTION

Estimates of Canadian requirements for both foreign and indigenous feedstocks were derived by forecasting such elements as the demand for petroleum products in Canada, the degree of refinery utilization and flexibility, the industry's own use and loss, the level of imports, regional transfers, and exports, and the use of feedstocks from natural gas plants. Details of each of the submissions prepared by the four major integrated oil companies - Gulf, Imperial, Shell, Texaco - and the corresponding estimates of the Board are presented in Appendix L.

As for indigenous heavy crude oil, forecasts were provided by Ashland, Gulf, Husky, Imperial, Pacific, PanCanadian, and Shell. Submittors, in general, based their WOV indigenous heavy crude oil forecasts on asphalt demand allowing, however, for the processing of some heavy crude oil in Ontario for manufacture of fuels and for shipments of heavy crude oil to Montreal. The Board's definition of heavy crude oil comprises Appendix "K" of the Report.

5.2 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

5.2.1 Views of Submittors

Forecasts of requirements for crude oil and equivalent are compared in Figures 5-1, 5-2, and 5-3. In general, Texaco's estimates were much higher than those of the other submittors. However the forecasts of Texaco and Shell for 1995 were about equal, and in that year they exceeded the Imperial and Gulf forecasts by approximately ten percent. On the whole, the estimated requirements for crude oil and equivalent tended to be lower (about 15 percent in 1985) than those presented at the 1976 Oil Supply and Requirements Hearing reflecting reduced product demand forecasts (see Chapter 4).

East of the Ottawa Valley

In the area EOV, companies had varying opinions as to anticipated volumes of product imports. Gulf and Imperial forecast zero imports; Texaco estimated imports would be constant at 23 Mb/d; Shell forecast imports would increase from 25 Mb/d in 1979 to 90 Mb/d in 1995. Whereas Gulf and Imperial foresaw virtually no exports, Texaco assumed exports of 44 Mb/d throughout the forecast period; Shell anticipated that exports would rise to 84 Mb/d by 1995. In the period 1978-1979, product transfers were

generally expected to take place from Quebec to WOV. Only Gulf indicated significant transfers thereafter (about 20 Mb/d) and these were eastward into EOV. Industry use and loss was estimated to be between 6 percent (Shell) and 7 percent (Texaco) of crude runs. Estimates of the average annual growth of total feedstock requirements varied between 0.2 percent (Gulf) and 1.3 percent (Shell). Gulf, Imperial, and Shell assumed runs of 250 Mb/d or more of indigenous feedstock in the area throughout the forecast period, whereas Texaco showed runs of 250 Mb/d in 1980 and 160 Mb/d in 1985, and no runs of domestic crude by 1990.

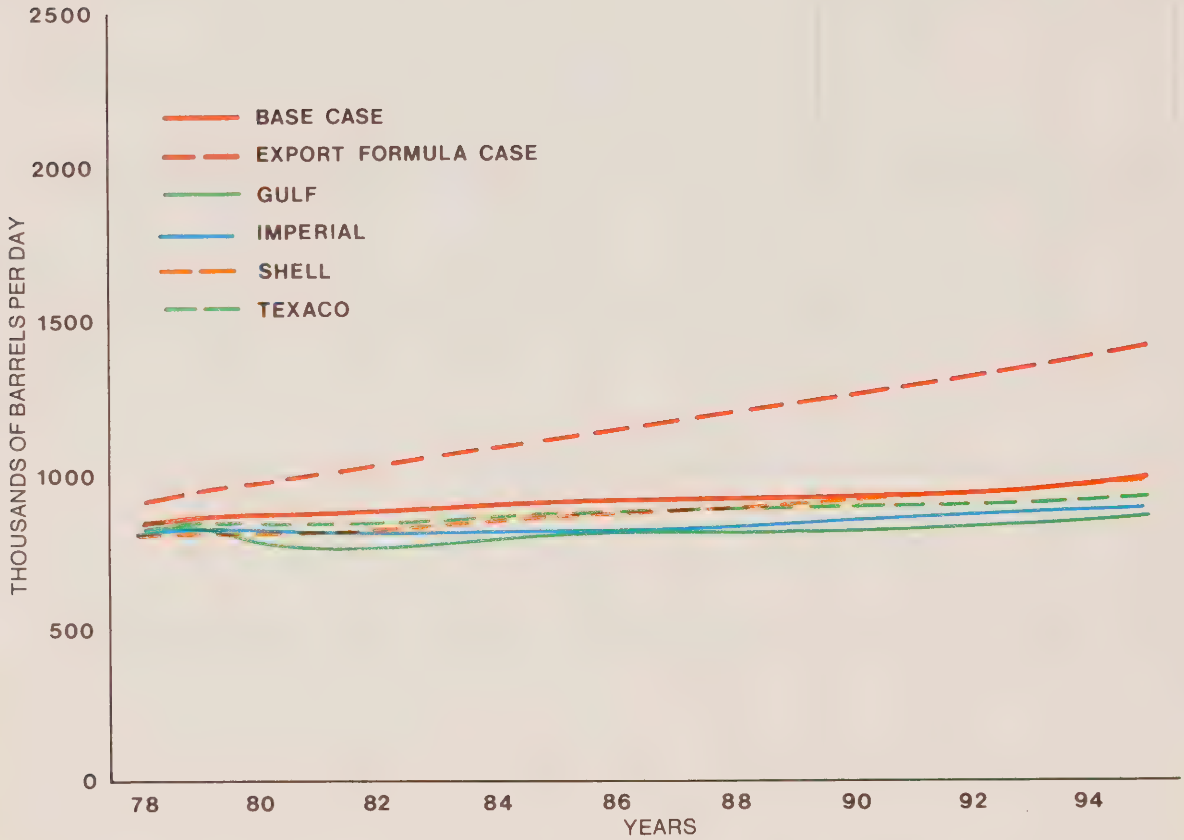


Figure 5-1 **REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT, EOV Comparison of Forecasts**

West of the Ottawa Valley

In the area WOV, all companies forecast the need to import refined petroleum products. Shell, with the highest estimate, provided for imports (heavy fuel oil) of 6 Mb/d in 1978 rising to 121 Mb/d in 1995. All companies also forecast exports. Shell estimated that after 1985 all exports (47 Mb/d in 1995) would be composed of motor gasoline, necessarily produced to meet other light product demands. Imperial's estimate included large exports of ethane, propane, and butanes, which would originate, however, from gas plants. Imperial's estimates of heavy fuel oil exports ranged from a high of 57 Mb/d in 1978 to a low of 14 Mb/d in 1995. Gulf similarly estimated decreasing

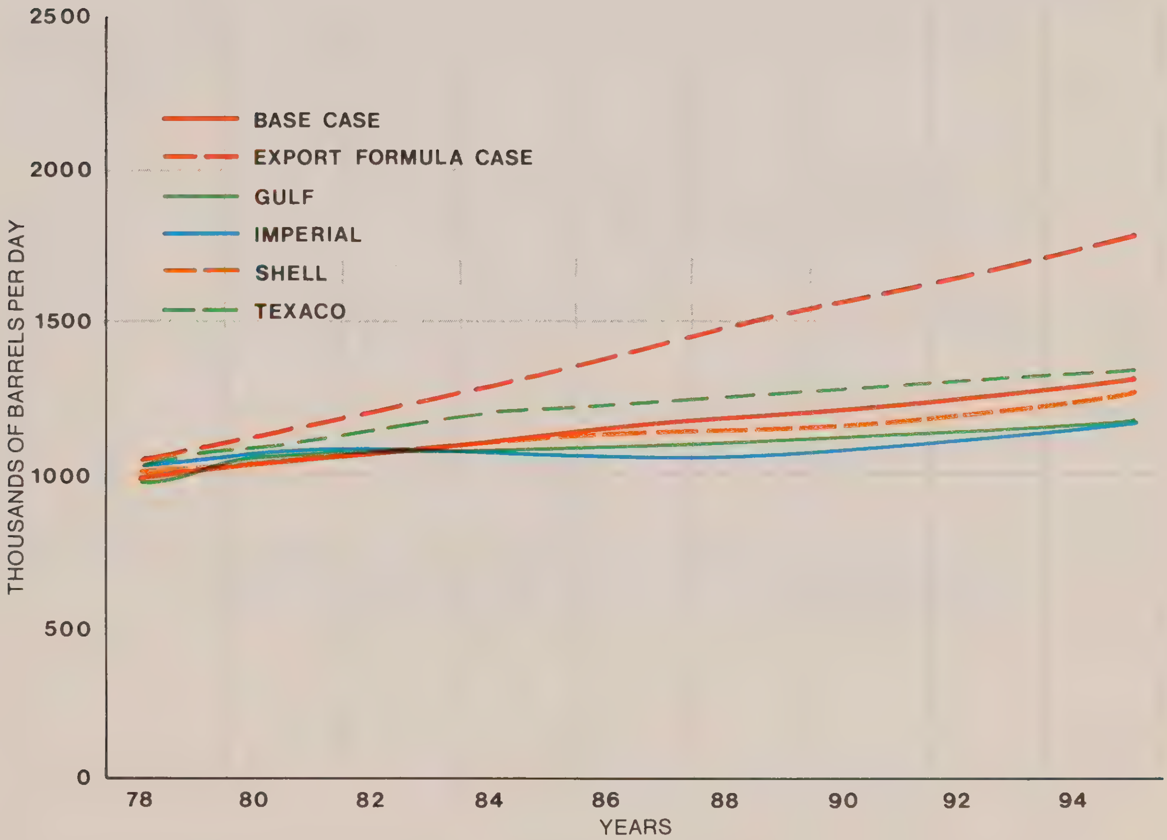


Figure 5-2 **REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT, WOV Comparison of Forecasts**

exports - from 46 Mb/d in 1978 to 14 Mb/d by 1995. On the other hand, Texaco foresaw exports of 76 Mb/d in 1978 rising to 90 Mb/d in 1995. Estimates of industry use and loss as a percentage of total crude runs varied from 3.5 percent (Gulf) to 6 percent (Shell). Submittors estimated that the volumes of butanes supplied by gas plants to refineries for blending would be between 10 Mb/d and 22 Mb/d. Estimates of average annual growth of total feedstocks for the period 1978 to 1995, varied between 0.9 percent (Imperial) and 1.5 percent (Shell).

5.2.2 Views of the Board

The Board's forecast of requirements for crude oil and equivalent is compared graphically with company forecasts in Figures 5-1, 5-2, and 5-3. The supporting data are shown in Appendix L.

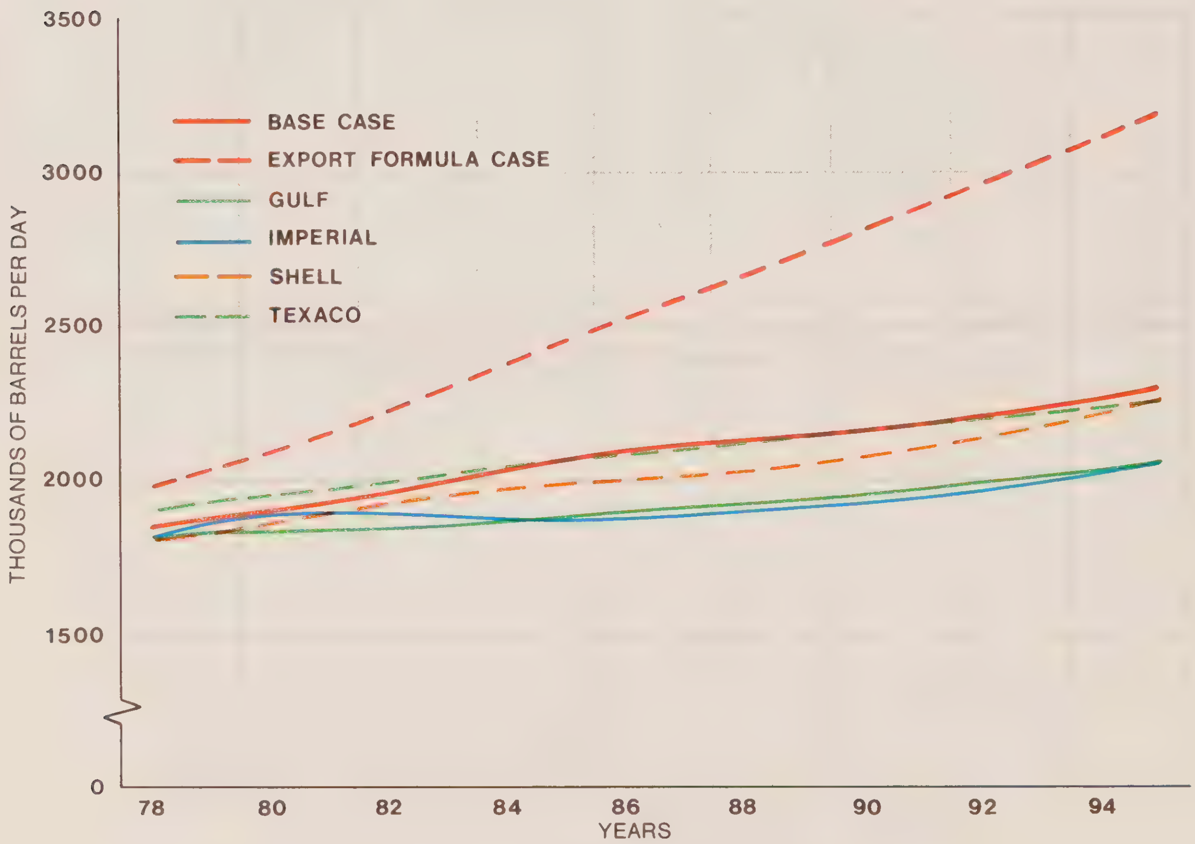


Figure 5-3 **REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT, CANADA Comparison of Forecasts**

East of the Ottawa Valley

Crude oil refining capacity in the area EOV, excluding the mothballed Come by Chance refinery, is still more than sufficient to meet product demands during the forecast period although small quantities of specialty products are expected to be imported. The Board assumes that feedstock will be run in the area at levels adequate to meet most domestic demands for products and to meet a continuing volume of exports. It is to be recognized that the level of exports achievable, whether in the short or longer-term future, must largely be conjectural at this time. Moreover, the Board is highly conscious of the fact that there is no easy solution to the problems arising from surplus refining capacity, which could result in plant closures.

The average annual growth of requirements EOV for crude oil and equivalent over the period of the Board's forecast is 0.9 percent.

West of the Ottawa Valley

It appears that refining capacity additions will be required in the Prairies and/or British Columbia during the latter part of the forecast period. In Ontario, capacity is expected to be sufficient until at least 1995. The Board has assumed that refining capacity in Western Canada will be expanded in a timely manner and that refineries in the area, in total, will run at levels sufficient to meet light oil demand. In consequence, some regional surpluses and deficits of heavy fuel oil are contemplated.

Over the forecast period, the Board's estimates reflect an average annual growth in requirements of crude oil and equivalent of 1.6 percent for the base case and 3.2 percent for the export formula case.

Total Requirements in Canada

In the Board's base forecast of the total requirements in Canada for crude oil and equivalent for the period 1978-1995, the average annual growth rate is 1.3 percent. In the export formula case, the growth is estimated to be 2.9 percent.

5.3 POTENTIAL RANGE OF THE REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

The high and low cases of petroleum product demand have been converted into estimates of total crude requirements using assumptions consistent with the base case. In the high case, the rate of growth of Canadian requirements during the forecast period is 2.7 percent; in the low case, the rate of growth is 0.6 percent. A graph comparing the range of these estimates with the base case is shown in Figure 5-4.

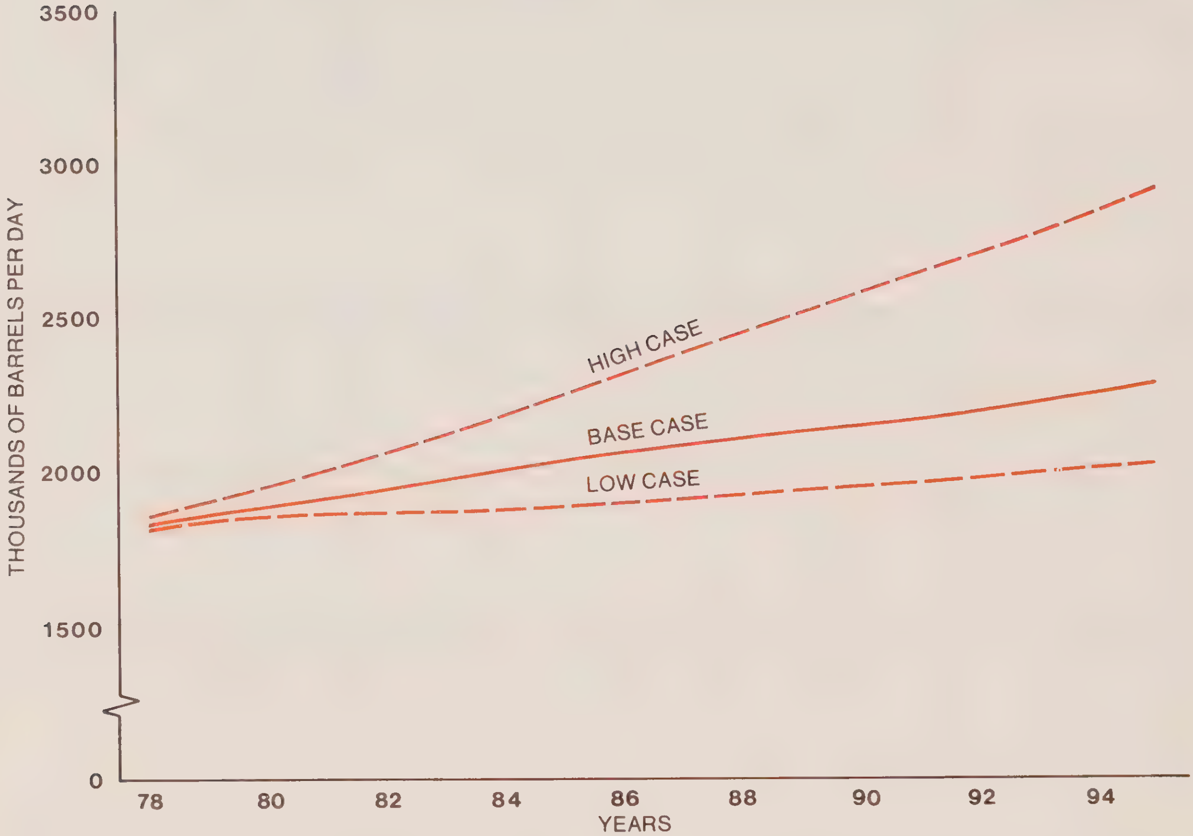


Figure 5-4 **REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT SCENARIOS, CANADA Range of NEB Forecasts**

The Board recognizes that there is a considerable degree of uncertainty as to future Canadian requirements for heavy crude oil, pentanes plus, and synthetic crude oil. Ranges of estimates of requirements have not, however, been made for these feedstocks.

5.4 REQUIREMENTS FOR INDIGENOUS HEAVY CRUDE OIL

5.4.1 Views of the Submittors

West of the Ottawa Valley

Submittors' anticipated requirements for indigenous heavy crude oil WOV are summarized in Table 5-1. In most cases, forecasts for indigenous heavy crude oil were tied to estimates of asphalt demand. There was, however, wide variation in the forecasts, in the main resulting from diverse treatment of requirements for Midale crude, Cold Lake oil, and heavy crude oil volumes assumed to be upgraded. Footnotes are provided in the table detailing these variations.

Ashland and PanCanadian each gave an analysis of Canadian asphalt demand along with details of its conversion into requirements for heavy crude oil. The background information contained in these submissions was useful in the preparation of the Board's assessment.

East of the Ottawa Valley

Table 5-2 summarizes the forecasts of the submittors with respect to requirements for indigenous heavy crude oil in the Montreal area. For the last hearing submittors based their projections on an anticipated market acceptance because refiners had only a few months of experience in processing Canadian crude oil. For this inquiry companies have had about two years of experience on which to project future requirements. PanCanadian and Ashland assumed that about half of the asphalt demand would be met from indigenous heavy crude oil.

While most submittors put future use of domestic heavy crude oil in Montreal at about 30 Mb/d, Imperial forecast that as Canadian heavy crude oil would be increasingly used for both asphalt and fuels manufacture, requirements would increase from 43 Mb/d in 1978 to 141 Mb/d in 1985. The company assumed also that flexibility would exist for the export of heavy fuel oil and the import of lighter crudes during the forecast period.

Table 5-1

WOV REQUIREMENTS FOR INDIGENOUS HEAVY CRUDE OIL

Comparison of Forecasts

(Thousands of Barrels per Day)

	Ashland(1)	Gulf(2)	Husky(3)	Imperial	Pacific	PanCanadian	Shell	NEB
1978	55	60	-	48	84	75	67	83
1979	57	63	-	51	88	77	72	87
1980	59	66	80	54	86	79	77	91
1985	66	124	99	80	99	86	101	111
1990	72	129	115	60(4)	115	92	105	130
1995	76	140	134	74(4)	134	96	90	150

(1) Excludes demand for Midale crude oil.
(2) Includes upgrading facility demand at 50 Mb/d from 1985 onwards.
(3) Excludes demand for Cold Lake crude oil.
(4) Constrained by supply availability.

Both Gulf and Imperial testified that in the event that the Sarnia-Montreal pipeline throughput increased to 325 Mb/d, another 8 Mb/d to 10 Mb/d of Canadian heavy crude oil would move to Montreal. Ashland and PanCanadian estimated that if all Montreal requirements of feedstocks for asphalt manufacture were supplied from Canadian heavy crudes, shipments to Montreal of indigenous heavy crude oil would increase by 25 Mb/d. Husky felt that the potential requirements for Canadian heavy crude oil in Montreal could reach 50 Mb/d, but that the Sarnia-Montreal pipeline would be reversed before that level was reached.

5.4.2 Views of the Board

West of the Ottawa Valley

The Board's approach to forecasting WOV requirements for heavy crude oil is unchanged from that used in the previous report. The Board has taken into consideration, however, a requirement for an additional 10 Mb/d in Ontario to be processed to produce fuel products. A revised yield of asphalt from heavy crudes has also been adopted. From historical demands for these grades it is assumed that the processing of 2.2 barrels of heavy crude will yield 1 barrel of asphalt. A breakdown of the components of the Board's forecast of heavy crude oil requirements is shown in Appendix M. Chapter 4 contains a discussion of the Board's estimate of asphalt requirements.

The Board's forecast of WOV requirements for indigenous heavy crude oil refers only to refinery requirements. The matter of upgrading of heavy crude oil is discussed more fully in Chapter 6.

East of the Ottawa Valley

The Board's forecast of indigenous heavy crude oil requirements in Montreal is based primarily on the testimony provided at the inquiry by Montreal users of heavy crude oil. Gulf stated that its current average requirement for heavy crude oil was 5 Mb/d, and Imperial said that it would take 30Mb/d - 35 Mb/d seasonally, thereby averaging 15 Mb/d-17 Mb/d. As BP and Petrofina did not present evidence on this matter at the hearing, it has been assumed that BP's current level of use would continue and that any plans that Petrofina may have for processing domestic heavy crude oil in the future would be part of the assumed growth. Texaco and Shell stated that they had no plans to run domestic heavy crude oil in Montreal during the forecast period.

Table 5-2

MONTREAL REQUIREMENTS FOR INDIGENOUS HEAVY CRUDE OIL

Comparison of Forecasts

(Thousands of Barrels per Day)

	Ashland	Gulf	Husky(1)	Imperial	Pacific	PanCanadian	Shell	NEB
1978	25	24	-	43	24	25	34	30
1979	25	24	-	60	28	25	34	35
1980	25	26	35	76	28	25	34	35
1985	25	29	-	141	28	25	34	40
1990	25	33	-	118(2)	28	25	34	46
1995	26	35	-	57(2)	28	26	20	52

(1) Assumes Sarnia-Montreal pipeline reversal.

(2) Constrained by supply availability.

The Board estimates that the 1978 requirement for indigenous crude oil in Montreal will be 30 Mb/d. This level reflects deliveries for the first half of the year. Deliveries are expected to rise to 35 Mb/d in 1979 and 1980 assuming Montreal shipments of 250 Mb/d. In the case where Montreal deliveries reach 350 Mb/d, corresponding heavy crude requirements would be 45 Mb/d. Thereafter, for both cases, use of domestic heavy crude oil in Montreal has been assumed to increase proportionally to the Board's estimate of asphalt demand in Quebec.

5.5 REQUIREMENTS FOR CONDENSATE AND SYNTHETIC CRUDE OIL

5.5.1 Views of Submittors

Gulf and Shell provided estimates of condensate requirements for total Canada; these estimates are shown in Appendix M. Both companies limited their forecast of requirements to their own projections of available supply. Petalta submitted that beginning in 1983 it would require 35 Mb/d of condensate to feed its proposed petrochemicals plant in Alberta.

Synthetic crude oil requirements estimates were provided by Gulf, Imperial, and Shell and are shown in Appendix M. Shell and Gulf assumed that all available synthetic crude oil would be refined in Canada; requirements of this material were therefore deemed to match supply.

5.5.2 Views of the Board

The Board forecast of requirements in Canada for segregated pentanes plus and synthetic crude oil is shown in Appendix M. The Board's estimate of refinery and petrochemical requirements for pentanes plus, unrestricted by supply, ranges from 65 Mb/d in 1978 to 105 Mb/d in 1995. In the early 1980's, supply becomes a constraining factor in meeting the Canadian demand (see Appendix M, page 7). At this time, some demand for pentanes plus must shift to other crude types or go unsatisfied. The supply-constrained forecast accounts for volumes blended into crude oil streams in addition to that produced in southern Alberta and northern British Columbia, which because of location and quality, are not expected to be suitable for Canadian needs. Petalta is assumed to come on stream in 1983.

The requirements for synthetic oils were estimated assuming that the entire output from the oil sands plants, including that of a heavy crude oil upgrading plant, would be processed in Canada. The split of requirements between Montreal and WOV was in the ratio of 1:3, based on data obtained from submissions; this ratio approximates the ratio of crude runs in Montreal to those WOV. Details of the Board's forecast are provided in Appendix M.

The ability of Canadian refiners to process synthetic crude oil is discussed in the following Section.

5.6 REFINERY FLEXIBILITY

The Board requested information on the flexibility of existing refineries to process available grades of crude oil in a manner that would minimize petroleum product surpluses. In order that product surpluses would be minimized, information was also sought on the need for new or modified facilities in Canada for processing synthetic crude oil and for upgrading heavy fuel oil.

5.6.1 Views of Submittors

The refining industry was described as entering a period of adjustment characterized by low growth, overcapacity, potential product-mix problems, and the continued need to adapt to penetration of oil markets by natural gas. It was generally conceded that surplus refining capacity and resulting low prices for petroleum products were creating an unprofitable situation. Gulf considered that this situation could not continue indefinitely, and Imperial noted that refiners and marketers would have to adapt in order to maintain even a low level of profitability. All refiners believed that the industry was capable of making orderly adjustments in the refining sector to satisfy changing market demands and feedstock availability. Such an outcome was said to be contingent upon the industry having flexibility in its selection of the crude oil charge, access to export markets for surplus heavy fuel oil, and the use of improved additives for particular products. In general, submittors were of the view that the refining industry could adjust to natural gas substitution for some demand currently served by imported oil on the assumption that gas "expansion" would take place slowly. Imperial and Gulf expressed concern that expansion of natural gas sales beyond the ability of the refining and marketing segments of the industry to adjust, would have serious consequences for the industry.

Gulf believed that although some product quality problems might arise with the use of synthetic crude oil, these should be solved because the gradual increase in synthetic oil availability would permit necessary research and operational changes. Imperial took the position that based on the current assessment of synthetic oil quality, only minor modifications to existing refinery equipment would be necessary in order to process this material and, for the most part, the use of synthetic oil would significantly reduce the amount of heavy fuel oil made by refineries in Ontario and Quebec. Shell noted, however, that the current quality of synthetic crude oil yields a relatively high proportion of cracking feedstock, and this material may have to be downgraded to heavy fuel oil in refineries with limited conversion capacity. Shell assumed that over the forecast period either sufficient cracking capacity would be provided in existing refineries or adequate upgrading facilities would be provided at oil sands sites. Petrosar explained that it could run synthetic oils, but that the yield of heavy fuel oil would exceed that from conventional crude oil. Ashland stated that the lack of hydrogenation facilities might limit runs of synthetic crude by individual facilities and that this situation might first arise in Ontario.

Refiners generally believed that the investment required for new facilities to upgrade heavy fuel oil to light products could not be justified, given the present low return on refining and marketing investments and the surplus refining capacity. Any upgrading of facilities would only reduce the already-low level of refinery utilization. Shell, Sun, Gulf, and Imperial noted that it would not be profitable to turn heavy fuel oil into light oils that are already in over-supply. Also, Imperial explained that by the late 1980s, the availability of synthetic crude oil should significantly reduce the amount of heavy fuel oil produced, so that any investment to reduce the production of heavy fuel would probably be obsolete in a very short time.

Gulf contended that rather than upgrade heavy fuel oil, it would be better to seek an agreement between Canada and the United States that would allow Canadian refiners access to the northeastern United States market on an equal footing with United States refiners. In its supplementary submission, Quebec suggested that the Federal Government enter into negotiations with the United States and offer further exports of Alberta gas in return for making Canadian refineries exporting into the northeast United States eligible for compensation under the United States entitlements program. Quebec pointed out that entitlement payments would be required to make Canadian refineries competitive with Caribbean refineries in this market.

Imperial, Gulf, and Shell suggested that the consumption of domestic-origin crude oil could be reduced if Petrosar were to purchase naphtha from conventional refiners for ethylene manufacture instead of skimming naphtha from light crude oil, with an attendant large production of heavy fuel oil. These companies indicated that there is sufficient quantity of naphtha of the appropriate quality available from conventional refiners to meet Petrosar's requirements. Petrosar expressed some concern about quality, but stated that it was currently considering the purchase of naphtha. However, the company was not in a position to indicate the maximum volume that it could run at this time. Whether the naphtha would be available at prices satisfactory to both buyer and seller was not evident at the hearing. Petrosar explained that as revenues derived from sales of fuel products contributed to its overall profitability, its objectives were to provide not only primary petrochemicals, but also fuel products to its customers at competitive prices. The company emphasized that one of the reasons for choosing crude oil as its basic raw material was its inability to obtain the long-term supply of naphtha needed to make its project viable. The crude unit is designed to run 170 Mb/d of Western Canadian crude oils in order to yield 55 Mb/d of naphtha, 77 Mb/d of residual fuel oil, and other fuel products. By utilizing other feedstock, crude oil processing could be reduced by 60 Mb/d and the residual fuel by almost 40 Mb/d without dramatically affecting the production of naphtha.

5.6.2 Views of the Board

It is generally recognized that the refining industry faces numerous problems including the variation of feedstock supply, surplus refining capacity, and changes to the mix of product requirements. The Board holds the view that although some investment in new equipment would be necessary, the refining industry appears capable of supplying products needed in Canada from available crude oil given a reasonable period of adjustment and the requisite flexibility to adapt to changing circumstances. On the evidence before it, the Board also believes that an increasing supply of synthetic crude oil for refiners is not likely to pose insuperable problems.

The Board still holds the opinion that domestic processing of indigenous feedstocks should increasingly aim to match product out-turns with the relevant mix of product requirements in Canada. The prospects of quickly achieving such a prescription are, however, poor. In part, this is so because refiners with excess capacity are competing hard amongst themselves in static or slow-growing product markets

with the result that retail prices for such staples as motor gasoline and heating oils are often significantly below the levels permitted.

With regard to petrochemicals, the steps already taken by Petrosar to reduce the crude oil input for the required output are in the right direction. It should be recognized that the evolution of this particular aspect of the refining industry's difficulties illustrates the fragility of assumptions over an uncertain future.

CHAPTER 6

SELF-RELIANCE AND SECURITY OF SUPPLY

6.1 INTRODUCTION

The Minister of Energy Mines and Resources requested the Board to investigate and report on a range of possible oil supply situations and the import dependency which these might occasion for consumers in British Columbia and Eastern Canada (see Appendix A). Import dependency is of course affected by a number of variables, two of which are discussed in this Chapter: the replacement of oil by other energy forms, and the upgrading of heavy crude oil to make it acceptable as a premium feedstock to Canadian refiners.

6.2 NEED FOR ADDITIONAL IMPORT FACILITIES

6.2.1. Views of Submittors

A number of submittors directly or indirectly criticized the Board for hearing evidence on the matter of additional import facilities, believing that the matter had already been adequately assessed. The Kitimat Oil Coalition argued that the matter of a west coast oil port had already been dealt with by Cabinet, and therefore, by implication it was unnecessary for the National Energy Board to consider the need for such a port in its deliberations. This position was supported by the Coalition Against Supertankers. The North Coast Committee to Save Our Shores believed that the need for a west coast oil port had been disposed of by the West Coast Oil Ports Inquiry, and questioned the Board's responsibility for reconsidering the matter. The United Fishermen and Allied Workers Union concluded in its submission that there was no need to build expensive new import pipelines on either of our coasts, provided that the public interest, not the interests of the "giant multi-national oil corporations", was placed first.

Gulf stated that although Canada would rely on imported crude oil to the extent of about 30 percent of feedstock requirements by 1995, new import facilities would not be required to meet Canadian domestic demand given expected conservation and oil supply development assumptions.

Imperial submitted that a strong supply development program might put Canada into a position to achieve the Federal Government's self-reliance target of limiting Canada's net oil imports by 1985 to one-third of total demand or 800 Mb/d, whichever is less. Failure to encourage oil production,

especially the two post-Syncrude oil sands plants, could increase Canada's net reliance on imported oil, with the consequent need for added import facilities. Imperial's base case showed that no additions to the existing import capability would be required during the forecast period.

Shell pointed out that any shortfall from its supply development forecast could create the need for additional pipeline and port facilities to handle increased crude oil imports.

Texaco stated that Canada's crude oil productive capacity would be insufficient to supply Canada's total needs during the forecast period, and that the country would be dependent upon foreign crude sources to the extent of 700 Mb/d in 1985 and 900 Mb/d in 1995. It also stated that Ontario refineries might require access to foreign crude oils within the next decade. Texaco considered the Portland-Montreal Pipeline system to be an important link in Canada's security of petroleum supply, and pointed out that subsequent to the commencement of deliveries of domestic crude to Montreal, part of the Portland-Montreal system had been mothballed, reducing its shipping capacity from 550 Mb/d to 292 Mb/d. The effects on the Portland-Montreal system of the recently announced intention to increase the supply of Canadian crude to Montreal would be as follows:

- if intermittent operation becomes necessary, operational requirements would preclude delivery of certain crude oils required for specialty products;

- if low throughputs prevailed for an extended period, power contracts would have to be modified or cancelled with no assurance that power could be restored at all locations;

- if low throughputs prevailed, it would have adverse affects on the operational efficiency of the tankage and marine terminal operations associated with the system.

Texaco recommended that from an economic standpoint, the minimum throughput of the Montreal-Portland Pipeline should be in the range of 200 Mb/d to 250 Mb/d, although the pipeline could be operationally viable at a minimum annual average of 125 Mb/d if throughput were not less than 150 Mb/d in the winter months.

On the basis of its forecast, Amoco did not see the need to provide facilities to bring more crude into Canada. HBOG, although it did not go so far as to state a need for an additional port, did point out that it would be to the economic advantage of Canada and that increased security of supply would result. Ashland concluded that new ports would be required to meet Canada's future oil requirements.

Ontario indicated that since the security of supply of foreign crude oil is highly uncertain, there is an urgent need for Canada to be self-sufficient in crude oil at the earliest possible date, and, because of the uncertainties associated with overseas supplies, the construction of additional crude oil pipelines designed to give Canada access to foreign crude oil should not be considered as an alternative to self-sufficiency. It also submitted that governments should encourage and stimulate activities that contribute toward self-sufficiency. Ontario also held the view that the Federal Government, and specifically the Department of Energy, Mines and Resources, should be a submittor at energy inquiries being conducted by the Board.

In its supplementary submission, Quebec pointed out that increasing deliveries to Montreal of Canadian crudes, including heavy oil and synthetic oil, must take into account the Quebec refineries' adaptation capabilities and the economics of new investments that would be required. Furthermore, Quebec pointed out that increased deliveries of Canadian crude could force Quebec refineries to terminate certain foreign supply contracts, creating possible difficulties in the future if these foreign sources were eventually required again.

6.2.2 Views of the Board

The Board concludes from its base-case estimates that refiners located WOV should be able to continue operating on indigenous supplies of crude oil until after 1995. Furthermore, some domestic crude oil should continue to be available for delivery to Montreal. However, considering the variability of supply and demand estimates prepared by the Board, and as illustrated in Figures 2-14 and 5-4, the Board sees no room for complacency.

At refining locations in Atlantic Canada and Quebec City, the Board believes the docking and oil-discharging facilities would be adequate to handle anticipated requirements for foreign crude oil during the forecast period. However, given the existing import facilities, refining locations situated WOV and in Montreal are considered to be vulnerable since in the event that a maximum dependency situation were to develop, that is one in which there would

be low indigenous supply and high requirements, these refineries might have to rely on imported crude oil in significant quantities.

In deriving the degree of potential dependency of refiners WOV and in Montreal, the Board has calculated the capability that indigenous supplies and the Portland-Montreal Pipeline have of meeting refiners' crude oil requirements. For illustrative purposes, Table 6-1 exemplifies how these crude requirements could be met in 1985 using high supply and low requirements scenarios (minimum dependency), base supply and requirements scenarios (base dependency), and low supply and high requirements scenarios (maximum dependency). For the purpose of estimating the effect of shut-in capacity on future producibility, it was assumed that production would be the sum of WOV requirements plus exports plus deliveries of 315 Mb/d to Montreal. Similar calculations were made for other years and the results are shown graphically in Figure 6-1.

Table 6-1

CALCULATION OF EXCESS CAPACITY OF EXISTING OIL IMPORT FACILITIES IN 1985

(Mb/d)

	Minimum Dependency	Base Dependency	Maximum Dependency
WOV Requirements	1042	1131	1244
Add: Montreal Requirements	508	550	614
Sub-Total	1550	1681	1858
Deduct: Indigenous supply	1599	1394	1223
Deduct: Existing Capacity of Portland-Montreal Pipeline	550	550	550
Sub-Total	2149	1944	1773
Excess Capacity of Existing Facilities	599	263	(85)*

* Figure in brackets represents a deficiency.

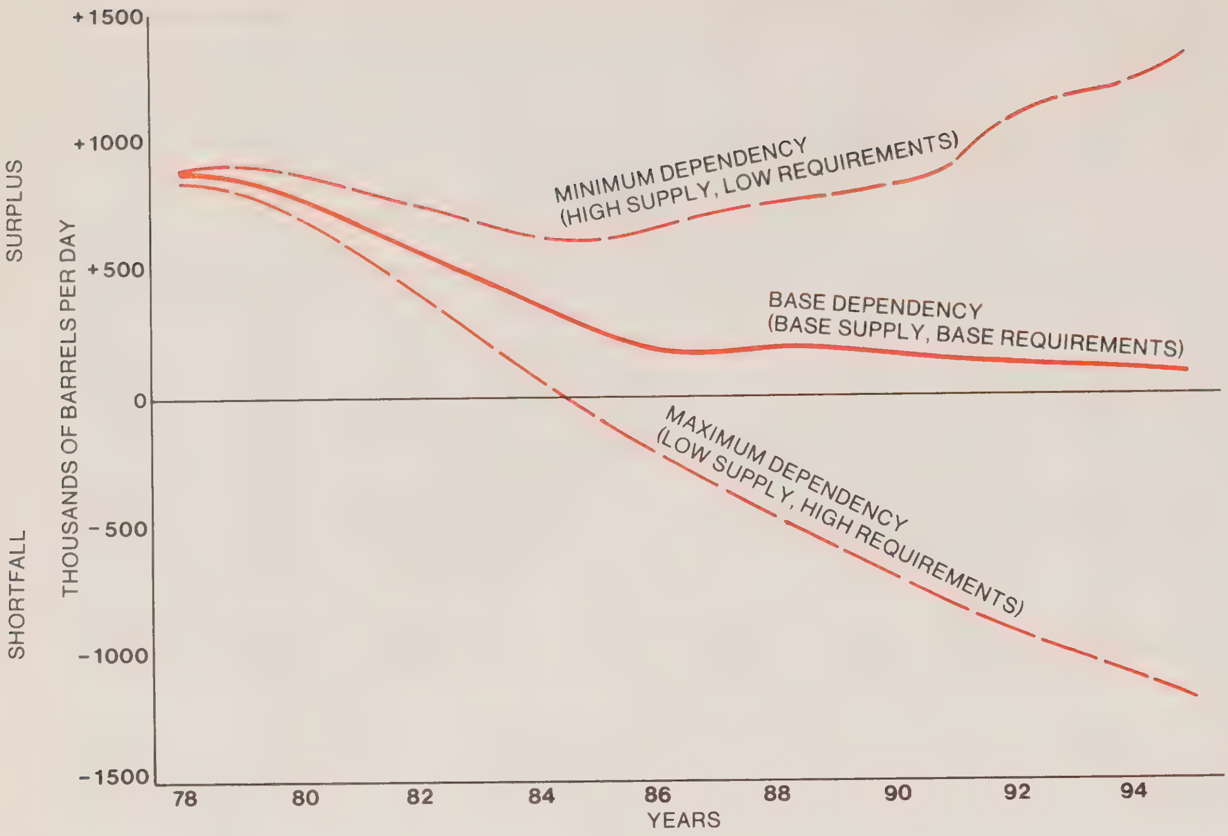


Figure 6-1 **CAPABILITY OF CANADA TO MEET ITS CRUDE OIL REQUIREMENTS FROM INDIGENOUS PRODUCTION AND EXISTING IMPORT FACILITIES**

Although no new facilities are seen to be required under the base-case estimates, the importance of maintaining the viability of the Portland-Montreal system must be stressed. In 1977, average crude oil receipts by Montreal refiners were 467 Mb/d; in May of 1978, receipts totalled only 373 Mb/d. If deliveries of domestic crude to Montreal were to increase to the 350 Mb/d level being considered, throughput on the Portland-Monteal system would be reduced to levels that could well threaten the commercial viability of continuing to operate the system; a shutdown could be detrimental to Canada's future security of supply. Accordingly, the Board feels that if domestic crude oil were available to increase the supply to Montreal to 350 Mb/d, deliveries at that level would not be warranted under existing circumstances; rather, 315 Mb/d, which is the approximate capacity of the IPL extension between Sarnia and Montreal, should be considered the maximum at this time.

6.3 POTENTIAL FOR REPLACEMENT OF OIL BY OTHER ENERGY FORMS

Increased substitution of natural gas and renewable energy for petroleum products was endorsed by many submittors as a way of increasing Canada's self-reliance. Any qualification was directed toward the degree to which the cost of self-reliance should be a limiting factor.

6.3.1 Views of Submittors

Gulf

Gulf indicated a number of methods by which the replacement of oil by other energy forms could be accomplished. These included extension of natural gas into new market areas, faster conversion from oil-heated households to other energy sources, a movement away from oil-driven vehicles, and conversion to renewable energy forms. Although Gulf did estimate that renewable energy not included in its forecast could possibly provide three to five percent of Canadian energy demands by 1995, it did not provide quantitative estimates of the potential any of these measures might have with respect to displacing oil. Gulf did not take into account expansion of natural gas service into markets not presently served by natural gas. In its view, such an expansion would not be economic and would merely exacerbate the problem of disposing of excess heavy fuel oil supplies. Gulf stated that displacement of heavy fuel oil by hog fuel was likely, particularly in British Columbia, but was not included in its forecast simply because of a lack of knowledge in this area.

Imperial

Imperial suggested that by 1990 natural gas would displace approximately 100 Mb/d of oil, but cautioned against pushing substitution beyond economic limits or at a pace beyond the refining industry's ability to adjust.

Shell

Shell believed the main opportunity for further substitution of oil by other energy forms was in the substitution of natural gas for oil, assuming certain conditions. Shell also estimated the volumes of oil that would be replaced if a natural gas pipeline were extended into the Maritimes. It held the opinion, however, that such a pipeline would not be an economic venture.

Texaco

Texaco assumed that by 1980 energy will be priced on an "energy equivalent basis". After 1980, Texaco foresaw interfuel substitution being limited to that induced by legislation, security of supply, or regional considerations. Texaco assumed that extension of natural gas service east of Montreal would be imprudent because of the increased cost that the extension would impose on eastern consumers ($300 million to $1000 million per year), and the very limited contribution it would make to reducing oil imports (less than four percent). As an alternative, Texaco suggested Canada should export surplus Alberta natural gas, with provision for repayment of equivalent supplies in the future.

AERCB

The Alberta Energy Resources Conservation Board believed that the potential for oil substitution in Alberta was limited because of the already small market share held by oil in the province. Fuel substitution from electrification of some heavy volume rail trackage in Alberta was estimated to reach 754,000 barrels per year in 1990 rising to 1,406,000 barrels in 1995.

N.B. Power

The New Brunswick Electric Power Commission did not quantify the amount of oil that could be replaced by other energy forms, but it did provide a series of recommendations that it felt would help reduce the oil import dependency of Eastern Canada through the development of electricity generating resources not dependent on oil as a fuel.

BCEC

The British Columbia Energy Commission included provision for the substitution of other forms of energy for oil over the forecast period in its base-case forecast of petroleum product demand. Although it noted that a study was underway regarding the feasibility of extending natural gas service to Vancouver Island, it provided no estimates on the quantity of oil to be displaced by gas. The Government of British Columbia, while recognizing the importance of self-reliance, warned against ignoring its costs. British

Columbia argued that it was not necessarily in Canada's best interest to pursue oil supply and demand targets to the point that either some Canadian oil is more expensive than imported oil, or that other indigenous fuels must be subsidized to encourage their use.

Newfoundland

Newfoundland suggested that the use of wood as an energy source is likely to grow, and that this growth would occur mainly in the rural portion of the residential sector, and possibly also to some extent in the wood-processing industries. Newfoundland also suggested that in the medium to long-term future, peat from Newfoundland's extensive peat lands could become a significant energy source. However, the major potential for the replacement of oil was seen to be in the area of electricity generation. If Newfoundland's "low scenario" energy demand growth occurred, and the Lower Churchill Falls hydro-electric project were not developed, then by 1985, 15 trillion Btu's per year of energy for thermal power generation would be required over and above the estimated requirements in Newfoundland's "high scenario". If this was entirely oil-based thermal generation, about 2.4 million barrels of oil per year would be required. By 1995, without the hydro-electric development, an estimated 36 trillion Btu's of energy for thermal generation would be required, which, under the high-scenario, would be met from hydro sources. If this additional thermal requirement was entirely oil-based, an additional annual requirement equal to about 5.8 million barrels of heavy fuel oil could result.

Nova Scotia

Nova Scotia presented two scenarios, in addition to its base-case forecast, that set out the potential replacement of oil in Nova Scotia by either natural gas or electricity. In the electricity substitution scenario, it was estimated that by 1980 fuel oil savings could reach the equivalent of 0.3 percent of total petroleum products consumed in Nova Scotia, and that by 1995 the savings could rise to 4 percent. Replacement of petroleum products under the natural gas substitution scenario amounted to 6 percent in 1985 and 14 percent in 1995.

Ontario

The Government of Ontario stated that the extent to which other energy forms should or could be substituted, should be determined primarily by the marketplace and that energy investment decisions must not ignore economic realities.

Quebec

Quebec believed that a substantial reduction in the demand for oil was essential. To this end, Quebec intended to develop the Province's hydro-electric potential and encourage the development of renewable energy sources such as solar, wind, and biomass. Quebec would also like to double the share of provincial energy demand met by natural gas. Thus, for the period 1976 to 1990, Quebec estimated the demand for oil in the Province should decrease at a rate of 1 percent to 1.8 percent per year. Quebec cautioned that since surplus fuel oil is regarded as a by-product and as such supports a marginal price, the artificial introduction of natural gas at a price below its present value would lead refiners to reduce the price of fuel oil to the equivalent level. Quebec felt that the situation could deteriorate to the point that weaker refineries would close.

Saskatchewan

Saskatchewan believed that electricity and renewable energy forms, rather than coal and natural gas, were most likely to replace oil in Saskatchewan over the forecast period. The bulk of this replacement would probably be by electricity used in the residential sector for space heating, most specifically in rural areas of the Province where natural gas is not available. In a recent forecast, the Saskatchewan Power Corporation estimated that the 3 percent market share held by electricity in the case of farm residences would increase to 11 percent by 1988.

CPA

The Canadian Petroleum Association maintained that although the replacement of oil by other energy forms was desirable to increase Canadian energy self-reliance and to permit indigenous oil reserves to meet a larger proportion of total Canadian requirements for oil, natural gas should not be forced into markets that could more economically be served by other energy forms. The CPA strongly advised against

intervention by Governments by way of subsidies on gas or other energy forms to capture markets from oil. Such intervention was believed to be ultimately counterproductive to the economy of the nation.

Canadian Wildlife

The Canadian Wildlife Federation stated that because of security of supply, the marketing of Arctic gas, and the domestic gas surplus, a policy of encouraging natural gas penetration would be beneficial. However, it believed further natural gas penetration by means of extension of the natural gas pipeline system into the Atlantic provinces could require large subsidies. Canadian Wildlife reserved judgement on the merits of implementing such a policy until the size of the subsidies are established, and the costs and benefits of increased market penetration are calculated.

Chevron Canada

Chevron Canada estimated current demand in British Columbia for heavy fuel oil to be about 25 Mb/d. Requirements were expected to be reduced to about 20 Mb/d by 1980 as a result of hog fuel projects presently underway, and energy conservation measures. If natural gas service was extended to Vancouver Island, heavy fuel oil demand at pulp mills was expected to immediately decrease by about 6 Mb/d to 7 Mb/d.

COAST

The Coalition Against Supertankers suggested a vertical-axis wind turbine be built for use as a research facility on the Queen Charlotte Islands, a region characterized by high winds, to examine problems and determine benefits that could, in the long-term, provide a substantial economic gain both on and off the islands. COAST also believed that a considerable potential exists in the Queen Charlottes to utilize wood waste as an energy source.

COFI

The Council of Forest Industries of British Columbia testified that, compared with the present level of 35 to 40 percent, the pulp and paper industry could theoretically become 89 percent self-sufficient in energy with the use of hog fuel; however, COFI believed that economic considerations made 60 to 65 percent self-sufficiency the most-likely level that could be attained within the next ten years. The forest industry was expected to remain British Columbia's largest consumer of heavy fuel oil.

Dome

Dome, while advocating the provision of additional markets for natural gas in Canada, believed that expanding the existing natural gas transmission system to serve presently-unconnected eastern markets could, in the long term, be more expensive and disruptive than other policy alternatives.

Gaz Metro

Gaz Metropolitain provided an oil-replacement forecast in addition to its base-case forecast. Under its substitution formula, natural gas sales would increase in 1985 by about 123 percent, and by 1995 would be 152 percent higher under the substitution scenario than under the base case. If energy conservation occurred as envisaged by Gaz Metro in its energy conservation scenarios the volume of petroleum replaced would be reduced by about 11 percent in 1985 and 12 percent in 1995.

Gaz Metro presented a list of policies that would encourage the substitution of natural gas, but stated that it would not be prepared to specify which policies it would recommend until the Board's natural gas hearing in October 1978.

HBOG

Hudson's Bay Oil and Gas Company believed that although natural gas could replace significant quantities of crude oil, there were various factors prohibiting spontaneous replacement. Consequently, it advocated that steps be taken to expand the Canadian market share of natural gas in areas already served by distribution systems, while allowing additional exports of natural gas under short-term licences.

IGUA

The Industrial Gas Users Association estimated a "promoted substitution" case under which, compared with its "no substitution" case, oil consumption would be reduced by 35.5 percent in 1985, and 55 percent in 1995. IGUA had not done any research to determine the practicability of obtaining this level of substitution.

IPAC

The Independent Petroleum Association of Canada believed that the Federal Government should encourage the use of natural gas in Canadian markets, particularly in Ontario and Quebec. To achieve this goal, IPAC suggested that the Federal Government facilitate the export of surplus residual fuel oils. IPAC also recommended that the Province of Quebec remove the sales tax that applies to natural gas used for residential purposes and that the Ontario Energy Commission provide greater flexibility in the price structure it approves.

Petrosar

Petrosar examined the potential for the replacement of oil products in Ontario by natural gas. It concluded that in the residential and commercial markets, lower gas prices or other conversion incentives are not likely to cause much further conversion from oil to gas. Petrosar believed that reducing natural gas prices in the industrial market would not likely result in further conversion from oil to gas. Petrosar concluded that relieving heavy fuel oil surpluses through exports and establishing confidence in the long-term supply of natural gas could help to increase the use of natural gas in place of oil in Ontario.

SPEC

SPEC strongly recommended the decentralization of energy sources, wherever possible, in accordance with the principles that all supply sources for the long-term future should:

- be environmentally benign in extraction and use;
- be socially benign in extraction and use;
- be renewable;
- achieve maximum social benefit per unit of primary energy.

SPEC specifically advocated development of: solar energy; biomass energy; hog fuel in British Columbia; municipal wastes energy; wind energy; and recycling of waste material with its attendant energy savings. SPEC opposed further development of energy derived from nuclear power plants.

Sun Oil and Ashland

Sun Oil stated that mandatory substitution of gas for oil is almost certain to result in a less-healthy economic situation, and suggested the alternative of exporting surplus natural gas and increasing crude oil shipments to Montreal. Sun Oil and Ashland commissioned Hycarb Engineering Limited to examine the potential for natural gas substitution of heavy fuel oil in the Provinces of Ontario and Quebec. As a result of this study, Hycarb determined that heavy fuel oil demand could be reduced in Ontario and Quebec by about 9 Mb/d in 1980, rising to 79 Mb/d in 1995.

TCPL, Northern and Central and Consumers'

TransCanada engaged Foster Research and Ralph Hedlin Associates to prepare a study entitled "Potential Substitution of Fuel Oils by Natural Gas in Canada 1976-1995". The same group prepared a similar study for the joint use of Northern and Central and Consumers', except that in this case the study was limited to Ontario. In the studies, they forecast two potential scenarios for replacing oil with other energy fuels. Under Scenario I, no substantial changes were made in existing market arrangements. Under Scenario II, it was assumed there were substantial changes in existing marketing arrangements because of Federal Government policies specifically designed to increase substitution. Under Scenario II, it was estimated that 105 trillion Btu's, or about 17 million barrels of fuel oil, could be replaced across the country by 1985, rising to 220 trillion Btu's, or about 35 million barrels of fuel oil, by 1995. TransCanada limited discussion of its substitution scenarios during the hearing, stating it felt it would be more appropriate to examine these matters in detail during the Board's natural gas hearing in October 1978.

Union Carbide

Union Carbide categorized the various options available for replacing oil by other energy forms as follows:

(a) Replacement of oil by natural gas;

(b) Replacement of oil by nuclear and hydro power;

(c) Gas exchanges with the USA in return for oil, coal, gas, or other advantages.

With regard to the replacement of oil by natural gas, Union Carbide believed that the size and extent of the "gas surplus" must be adequately measured, over both the short and the long term, before a major shift to natural gas should be recommended at the expense of other energy forms.

Union Carbide suggested that once this was established, greater gas use could be encouraged by:

(a) economically justifiable improvements to refineries in order to reduce heavy fuel oil output;

(b) restriction of fuel oil imports except where shortages were shown to exist, or where imports were needed to satisfy a unique quality requirement or were of economic benefit due to geographical distribution patterns;

(c) establishment of consistent policies, reasonable export taxes, and term licences for fuel oil exports.

Union Carbide opposed any major natural gas network extension east of Montreal until the marketability of gas in Montreal could be shown to be improved and until the long-term economics of further extensions could be demonstrated. Union Carbide also opposed the encouragement of natural gas penetration through lower gas prices. It felt that the only significant effect of lower gas prices would be lower energy prices for all hydrocarbon fuels, which would erode conservation efforts. A forced conversion to natural gas was seen by Union Carbide as having dire consequences for both the refining and petrochemical industries.

Union Carbide favoured national and provincial policies for the development of electric power from both renewable and non-renewable sources. It believed that policies for the increased use of electric power should recognize the need for equitable power rate structures based on embedded cost of service.

Union Carbide supported energy exchanges and in particular:

(a) the exchange of Canadian natural gas with the United States in return for crude oil to the Maritimes and access to joint petroleum strategic reserves;

(b) the exchange of crude oils to reduce oil transportation costs;

(c) exchanges of natural gas on a time basis.

6.3.2. Views of the Board

The Board believes that there is considerable potential for interfuel substitution among all energy forms. With respect to the substitution of gas for oil in markets not now served by gas, the Board's views have been expressed in Section 3.2.4.2. of this Report.

It is apparent that a rapid expansion of gas service into markets now using petroleum fuels would create additional problems for refineries currently operating at less than optimum capacity. Some rationalization of refining operations would likely occur over time and some liberalization of export policy with respect to oil products from Ontario could assist refiners in that Province. Refiners in Quebec and the Maritimes could be aided by obtaining additional access to export markets in the north-eastern United States.

With respect to the use of renewable energy, the Board recognizes that over the long run, alternative renewable energy sources could contribute significantly to Canada's energy supply. In arriving at its Reasons for Decision, Northern Pipelines, published in June 1977, the Board conducted a comprehensive analysis of the emerging alternative renewable energy sources. The forecasting of market shares for these alternative renewable energy sources is an extremely subjective exercise because of the number of assumptions that must be made and the inherent uncertainties involved in developing new technology.

In the light of the evidence received, the Board perceives no justification for altering its forecast of the market share of Canada's primary energy demand that will be met by alternative renewable energy sources, from the level that it forecast in its 1977 Reasons for Decision.

The Board sees a potential for solar heating in the residential and commercial sectors, for the use of biomass in the industrial and transportation sectors, and for the use of wind in electric power generation in certain special applications. The share of the market for each is assumed to vary among regions, but the overall share of Canada's primary energy demand that the Board estimates will be met by alternative renewable energy sources, is about 1.5 percent in 1995.

The Board recognizes that wood is currently used in significant quantities as an energy source in Canada. One area of particular significance is the use of hog fuel in the pulp and paper industry. Although a present lack of sufficient historical data precluded the Board from including the demand for wood in its total energy demand forecast, the Board has examined the use of wood as it relates to possible future displacement of other energy types. The Board's analysis of the evidence put forward in this area leads it to believe that there will likely be significant conversions from heavy fuel oil to hog fuel in the pulp and paper industry during the forecast period. Its forecast of demand for heavy fuel oil is on average approximately 25 percent lower in British Columbia than it would have been had expected conversions to hog fuel not been taken into account.

The Board also recognizes that the Minister of Energy, Mines and Resources has announced a $380 million program that, over the next five years, will provide incentives to encourage the development and use of renewable energy resources, particularly, forest waste and solar energy. The Board believes this is a positive step that could lead to a level of renewable energy use well above that presently forecast by the Board. However, the many uncertainties involved in attempting to quantify the impact of such a program in the very early stages of its implementation make it impossible for the Board to account for the results of such a program in its current energy demand forecast.

6.4 HEAVY CRUDE OIL UPGRADING

The construction of a heavy crude oil upgrading facility would provide Canada with the capacity to convert heavy crude oil into a synthetic light crude oil suitable to be run in existing Canadian refineries. Heavy crude oil now being exported could be upgraded to serve Canadian needs.

6.4.1 Views of the Submittors

Husky

Husky's proposed 100 Mb/d heavy oil upgrading plant for the Lloydminster area would process Western Canadian heavy crudes into sweet 34-35 gravity oil acceptable to all Canadian refineries. The company stated that it may be desirable to build the plant in 50 Mb/d stages. The plant was still in the design stage and Husky estimated that three years would be required to build the plant after all approvals were obtained. It was Husky's view that Canada's energy strategy of limiting imports can best be served by upgrading heavy crude oils and bitumens, as upgrading would stabilize heavy crude oil production and encourage enhanced recovery. The company expressed concern over the availability of diluent and noted that if an upgrading plant were built close to the heavy crude oil source, then diluent could be re-cycled. Husky did not feel that it would be necessary to develop feedstock for the whole plant before it is built.

Pacific

Pacific indicated that it was currently studying, with a consortium, the feasibility of building a 50 Mb/d-100 Mb/d plant in Alberta. This facility, which could be on stream as early as 1983, would process a mixture of conventional heavy crude oil and Cold Lake production into a light synthetic crude oil. Pacific indicated that economic evaluation of its plant had not been finalized, but it estimated a 100 Mb/d plant would cost $580 million and that the cost of upgrading would be $5.83 per barrel in 1982 dollars. Pacific saw the major advantages of building an upgrading plant to be:

- A commercial-sized project would allow small increments of production to come on stream and hence many more companies could participate;

- The plant would contribute to Canada's oil supply by providing a market for otherwise unusable oil;

- The plant would provide a stable market for heavy crude oil and thereby encourage exploration and development by enhanced recovery;

- The plant would provide light crude oil, reduce Canadian imports, reduce Canada's deficit on international transactions, and increase Canada's self-sufficiency;

Pacific also felt that traditional Canadian outlets were insufficient and United States markets too uncertain to provide the necessary incentives to cause active development of heavy crude oil reserves.

Amoco

It appeared to Amoco that there would be one heavy oil upgrading plant ready to go on stream in 1983, and that there was potential for developing other upgrading plants, while still satisfying United States markets.

Ashland

Ashland assumed that if a heavy crude oil upgrading plant were built, the supply thereby induced would add 100 Mb/d to the potential producibility. The cost of a new centralized facility in Western Canada was estimated to be $4000 to $6000 per daily barrel in 1977 dollars, which is equivalent to total upgrading costs of $3.75 to $5.10 per barrel. Ashland indicated that current price differentials are not sufficient to justify upgrading, and that increases in the price differential and new incentives are required to make such investments viable.

Ashland pointed out that the refineries in the U.S. Northern Tier were still a prime market for Canadian heavy crude oil, but that as these refiners were installing additional flexibility in crude supply systems, this market would become more competitive. Ashland indicated that there was potential for additional use of heavy crude oil in Montreal.

Gulf

Gulf assumed, based on public disclosures to that effect, that a heavy crude oil upgrading plant would go on stream no earlier than 1983 causing a shift in crude oil demand of 50 Mb/d from light to heavy. Gulf had the view that supply was sufficient to support a 50 Mb/d plant. Gulf estimated that the cost of a plant would be $450 million-$700 million and that the operating cost could reach as high as $4.00 per barrel. In its estimate of supply of heavy crude oil, Gulf assumed that there would be an incentive to increase supply, and that part of the incentive would be provided by an upgrading plant or the development of some market.

HBOG

HBOG supported the concept of constructing a major heavy crude oil upgrading facility because a single facility would offer economies of scale not available to individual refiners, and because diluent supply may not be available to move the heavy oil to Eastern Canadian or U.S. markets. HBOG suggested that heavy oil development as well as oil sands development is required to achieve self-reliance. The company indicated that governments must be prepared to accept a lower portion of revenues from these projects than from conventional producing operations, that international prices must apply, and that market access must be assured before projects can proceed as private sector undertakings.

Imperial

It was the view of Imperial that there would not likely be significant volumes of conventional heavy crude oil available in excess of volumes that could be absorbed by domestic and export markets. Imperial predicted that if an upgrading plant were on production by 1985, the plant might not have any supply by 1995.

The company expected that the U.S. market would continue to be available in significant volume at prices recognizing the desirable asphalt qualities of Canadian heavy crudes.

If an upgrading plant were to be built, Imperial believed that it could probably be on stream by 1985, but that it would not be economic to process Cold Lake oil in such a plant.

Murphy

With regard to the economics of upgrading , the question arose as to whether an increase in the price differential between light and heavy crudes was justifiable. It was Murphy's view that a reduction in heavy oil or oil sands revenue to the producer would be counter-productive. Murphy said that what was needed now was experimentation and experience with tertiary recovery, and the more industry participation that could be encouraged, the sooner heavy oil would contribute energy in volume.

PanCanadian

PanCanadian held the view that Canadian heavy crude oil would remain in strong demand in the U.S., assuming it is priced competitively, despite the availability of alternative supplies to U.S. refiners. The company, however, endorsed the concept of upgrading of conventional heavy crudes where the upgrading would result in the exploration for new reserves or the development of new technology to produce existing but unrecoverable reserves. PanCanadiàn believed there was no need to upgrade Bow River and Weyburn-Midale type crudes, and that U.S. Northern Tier and Montreal markets should be retained; this may allow new recovery projects to proceed without first building an upgrading plant. The company believed that there was insufficient heavy crude oil available to supply a 100 Mb/d plant.

Saskatchewan

Saskatchewan stated that upgrading would be needed if there were difficulties in marketing heavy crude oil in the United States, and that upgrading at the point of production would be more feasible than doing so at the refineries. It stated that the advantages of upgrading include:

- a reduction of market uncertainties;

- provision of a seasonally-stable market not dependent upon the relatively small seasonally-fluctuating and slowly-growing asphalt market;

- provision of a means to use heavy crude oil in Canada, thus improving Canada's security of supply, and reducing foreign exchange requirements to pay for oil imports.

Shell

It was Shell's view, assuming Canadian refinery requirements for heavy crude were met first, that there would be insufficient heavy crude oil available to amortize the capital cost of an upgrading plant of any size over a reasonable time frame. Shell indicated that the minimum economic size of an upgrading plant would be about 50 Mb/d. According to its estimates, by 1990, some six years into the amortization period, the total supply of heavy crude would be less than refinery plus upgrading requirements, and by 1995 there would be close to zero feedstock available for upgrading.

Texaco

Texaco indicated that there would appear to be the ability to develop producibility for upgrading; it had serious doubts however that this could be developed economically. Texaco did not favor processing Lloydminster or Bow River crudes in an upgrading plant thereby destroying their high-value asphaltic properties.

6.4.2 Views of the Board

Table 6-2 shows the Board's base cases for supply and requirements for heavy crude oil in Canada. The table shows the effect on the net supply of heavy crude oil of assuming that an upgrading facility will begin processing heavy crude oil in 1985. The demand shown includes requirements for heavy crude oil assuming total deliveries to Montreal will be 250 Mb/d ("250 case") and 350 Mb/d ("350 case"). Given that a heavy crude oil upgrading plant would receive priority in obtaining feedstocks, some amount of Canadian heavy crude oil would not be available to Canadian refineries near the end of the forecast period; however, these shortfalls would be rather small.

Table 6-2

HEAVY CRUDE OIL
SUPPLY AND REQUIREMENTS

Mb/d

	Total Supply	Upgrading Feedstock	Net Supply	Requirements 250 case	Requirements 350 case	Surplus 250 case	Surplus 350 case
1978	235	-	235	113	113	122	122
1979	239	-	239	122	132	117	107
1980	234	-	234	126	136	108	98
1985	221	50	171	151	163	20	8
1990	243	50	193	176	190	17	3
1995	250	50	200	202	218	(2)*	(18)*

* Figures in brackets indicate a deficit.

The Board holds the view that the volume of heavy crude oil expected to be available during the forecast period could be marketed without the construction of an upgrading facility. Imperial presented a scenario of high requirements for heavy crude oil in Montreal that essentially assumed that all available heavy crudes could be run in existing refineries. The Board believes this situation to be remote given the availability of foreign crude oil at Montreal and the prevailing price differences between light and heavy crude oils. The Board concludes, however, that the export market for heavy crude oil could be maintained, given that prices are competitive with alternative feedstocks. The Board assumes that producers would avail themselves of that opportunity until an upgrading plant went into operation.

The Board accepts that diluent will be required to enable Lloydminster and Cold Lake oil to be transported to eastern Canadian or U.S. markets. However, the Board is unable to determine whether during the forecast period a lack of diluent supply will necessitate upgrading.

Although condensate availability could diminish if it is required in Alberta for petrochemical feedstocks, other materials may prove to be suitable substitutes.

From the evidence presented it appears to the Board that upgrading will cost between $4.00 and $6.00 per barrel. At present, the Canadian price of light crude oils exceeds the price of heavy crude oils by less than this amount. Justification of upgrading however, cannot be based solely on the difference in value between light and heavy crude oil. Account must be taken of factors such as the availability of markets for any heavy crude oil not upgraded, the supply of diluent, and the objectives of self-reliance.

The Board also observes that as the price differential between light and heavy crude oil increases, Canadian refiners are more likely to increase runs of heavy crude oil. It may be that substantial additional quantities of heavy crude would be run in Canadian refineries if the price difference approached upgrading costs. Widening of the price difference, however, has the consequence of lowering returns to producers, and, hence, has a negative impact on heavy oil development economics.

In summary, the Board is of the view that the potential exists for heavy crude oil from Lloydminster-type reservoirs to satisfy significant Canadian oil needs, but that the key to obtaining this oil is through large scale economic application of thermal recovery techniques. If thermal recovery of heavy crude oil is shown to have successful application to a large portion of the presently mapped oil in place, then upgrading facilities will be required. The Board has assumed for its base case of oil supply that an upgrading plant would come on stream in 1985 supplying 45 Mb/d of synthetic light crude oil obtained from upgrading 50 Mb/d of heavy crude oil.

CHAPTER 7

PORTS OF ENTRY AND OIL PIPELINE FACILITIES

7.1 INTRODUCTION AND VIEWS OF THE BOARD

In a preceding chapter the Board has indicated that Canada, in providing for its oil requirements during at least the next decade and a half, should place emphasis on the expeditious development of its oil sands while sustaining the development of conventional oil. Assuming this course is followed, the supply-demand outlook emerging from this inquiry indicates that there is no general need to expand or augment existing facilities for the importation of offshore oil. This is not to say that particular circumstances will not give rise to applications being processed by the Board for facilities associated with import proposals based on factors not directly related to Canada's own supply-demand outlook. It is important that the Board must not prejudge such applications.

Against this background, it is appropriate and useful to include in this report information and observations on the various possibilities for future oil import facilities described to the Board during the inquiry.

7.2 EXISTING FACILITIES AND POSSIBLE EXPANSIONS

The facilities existing today are the major oil trunk lines that move oil from the producing regions to the refining centres in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, and Quebec. These are the systems that might be modified or expanded as part of a major oil transportation project.

Trans Mountain Pipe Line

Trans Mountain stated that its present system consists of 718 miles of 24-inch-diameter pipe extending from Edmonton to Vancouver with connections to the Westridge Marine Terminal and Trans Mountain Oil Pipe Line Corporation's system at the International boundary. The present pumping capacity of the system is 410 Mb/d of oil. The present storage capacity is approximately 4,350,000 barrels.

Trans Mountain stated that its marine loading terminal at Westridge on Burrard Inlet had a delivery capability of 25,000 barrels of oil per hour, and that the propane storage facility had a capacity to process 10,000 barrels per day. The dock can accommodate tankers of up to 45,000 D.W.T., and, with minor dredging, could accommodate vessels of up to 65,000 D.W.T.

It was also noted that all five refineries in southern British Columbia are connected to the Trans Mountain system and that four refineries in the State of Washington are connected through the facilities of Trans Mountain Oil Pipe Line Corporation.

Interprovincial Pipe Line

Interprovincial and its wholly-owned subsidiary, Lakehead Pipe Line Co. Inc., own and operate a pipeline system for the transportation of oil and other liquid hydrocarbons. The portion of the system that is in Canada is owned and operated by Interprovincial, and the portion in the United States is owned and operated by Lakehead.

The Interprovincial-Lakehead system extends 2,300 miles from Edmonton across the Canadian prairies, through the Great Lakes region of the United States to Sarnia, Toronto, and Montreal, with a lateral line to Buffalo. The present design capacity of the system, measured at the Manitoba/North Dakota international border, is 1,528 Mb/d, and the total storage capacity of the Interprovincial/Lakehead system is 16,246,000 barrels.

The extension from Sarnia to Montreal consists of 517 miles of 30-inch-diameter pipe. It was noted that with the installation of additional pumping units the light crude oil capacity of this portion of the line could be increased from its current level of 690 Mb/d. With certain modifications, the flow of oil through the extension could be reversed.

Interprovincial stated that deliveries from the system are made in the Prairie Provinces, the Provinces of Ontario and Quebec, and in the Great Lakes area of the United States directly to refineries or through connecting pipelines of other pipeline companies. Average deliveries in Canada and the United States in 1977 were 1,400 Mb/d.

Portland-Montreal Pipe Line

The Portland-Montreal pipeline is approximately 236 miles long, 70 miles being in Canada and 166 miles being in the United States. The system design capacity is 550 Mb/d and the present active system capacity is 292 Mb/d. The present storage capacity is approximately 3,900,000 barrels.

Since mid-1976, the system has been operating considerably below design capacity because Montreal has been receiving approximately 250 Mb/d of its oil requirements from Western Canada via the Interprovincial system.

7.3 NEW FACILITIES

Many submittors presented views on possible new Canadian and American ports-of-entry and potential oil pipeline facilities. These facilities would connect either the Atlantic or Pacific ocean ports with the present transportation systems or the refining centres themselves. Submittors discussed as well the implementation of an Arctic transportation system involving ports, tankers, and Class 10 icebreakers. Figure 7-1 illustrates the routing of present and potential oil-transportation facilities. A description of the potential transportation projects follows.

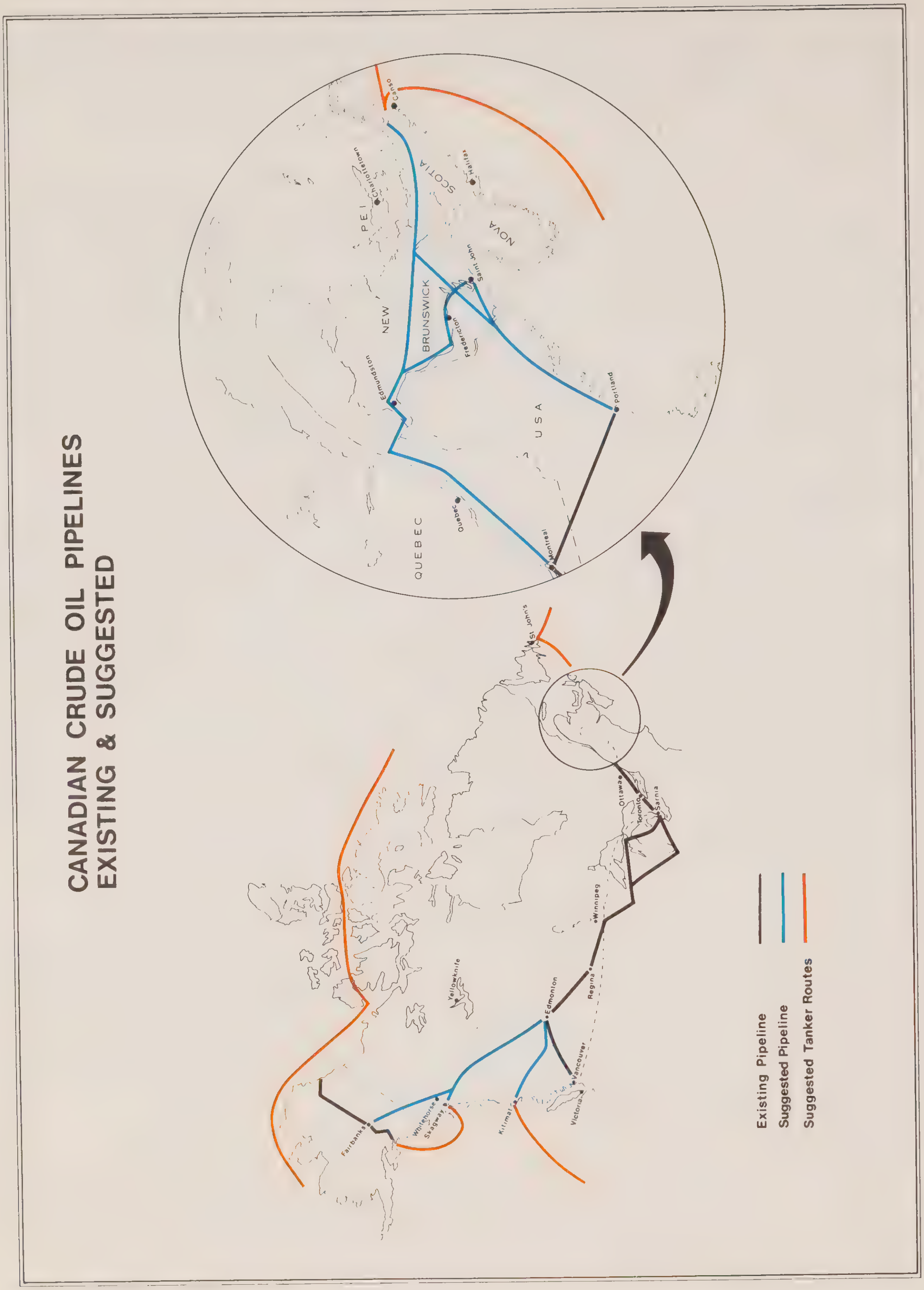
Foothills Project

Foothills presented four potential oil transportation systems of 30-inch-diameter and 500 Mb/d capacity, each utilizing portions of the Alaska Highway gas pipeline corridor. These would permit the transportation of Prudhoe Bay and foreign imported oil in parallel with the transportation of Prudhoe Bay gas. Two of the studies considered the receipt of oil at the Alyeska Pump Station No. 9 at Delta Junction, Alaska for delivery either to Interprovincial at Edmonton or to a connection of the Rainbow-AGTL systems at Keg River, Alberta for trans-shipment to Interprovincial. The other two cases considered Alaskan port facilities at Haines and Skagway using pipeline facilities to Edmonton and Keg River, as previously described.

Even though all four projects were for transporting oil to U.S. markets, it was submitted that they would be of benefit to Canada since they would extend the useful life of existing Canadian oil pipelines and would reduce the unit-transportation costs associated with those pipelines. Also, any of these systems would provide an access for foreign oil to Canadian refineries.

Kitimat Project

Kitimat submitted revised details of its Application presently before the Board for a Certificate of Public Convenience and Necessity for a potential oil port and a



CANADIAN CRUDE OIL PIPELINES
EXISTING & SUGGESTED
Existing Pipeline
Suggested Pipeline
Suggested Tanker Routes
Fairbanks
Whitehorse
Skagway
Kitimat
Vancouver
Victoria
Edmonton
Yellowknife
Regina
Winnipeg
Sarnia
Toronto
Ottawa
St. John's
QUEBEC
Quebec
Montreal
NEW
BRUNSWICK
Edmundston
Fredericton
Saint John
NOVA
SCOTIA
Halifax
P E I
Charlottetown
Canso
U S A
Portland

Figure 7-1

36-inch-diameter pipeline extending from Kitimat, B.C. to Edmonton, Alberta. This system would interconnect with the Interprovincial system to facilitate the movement of Alaskan and offshore oil to the refining centres in the northern and central United States as far east as Chicago and Buffalo. The expected capacity of the system was given as 450 Mb/d, expanding to 900 Mb/d.

Kitimat stated that, should Canada require additional access to imported oil, the Kitimat Project could provide that access, especially to the area WOV.

HBOG stated that it supported the Kitimat Project. HBOG gave the opinion that the Northern Tier U.S. refineries would provide the principal economic justification for the facilities, and that Canada would benefit, at minimal economic cost, from the additional options and flexibility that the pipeline could provide.

SPEC, COAST, the Kitimat Oil Coalition, SOS, the UFAWU, the Sierra Club, the Union of B.C. Indian Chiefs, the Vancouver Board of Trade, COFI, the Canadian Wildlife Federation, and the Government of B.C. all indicated, to varying degrees, their concerns regarding increased tanker traffic into west coast oil ports.

Trans Mountain Project

Trans Mountain presented four potential possibilities for the importation of oil to the Vancouver area as well as the reversal of the Trans Mountain system. These possibilities included: the importation of 150 Mb/d of oil at the Westridge Dock for use in the Vancouver area; the importation of 150 Mb/d of oil at Roberts Bank for use in the Vancouver area; the importation of 450 Mb/d of oil at Roberts Bank, of which 150 Mb/d would be used in the Vancouver area and 300 Mb/d would be trans-shipped to Edmonton; the importation of 150 Mb/d of oil from a delivery point at North Bend located south-east of Seattle, Washington for use in the Vancouver area.

In the submissions and evidence of the Vancouver Board of Trade, Chevron Standard, Imperial, Gulf, and the Province of B.C., it was urged that the refineries in British Columbia continue to be supplied with Western Canadian oil rather than imported crude.

Arctic Projects

Dome presented a conceptual plan for an Arctic marine-transportation system. This system would consist of an offshore-production facility, a loading facility, Class 10 ice-breakers, and tankers for the transportation of liquid hydrocarbons from the Beaufort Sea to southern markets. It was considered that 1985 would be the earliest date that this system could be in operation.

Panarctic submitted details of a possible oil pipeline and oil port in the Cameron Island - Bathurst Island region of the Arctic. Should the reserves be proved and no undue problems encountered in obtaining the appropriate government approvals, this system could be capable of shipping approximately 50 Mb/d of oil to Eastern Canada by 1982.

Interprovincial Project

Interprovincial presented an oil-delivery scenario that assumed the receipt of oil at Edmonton in quantities greater than presently being received. The volumes would be sufficient to satisfy the Canadian requirements west of Montreal as well as to supply feed stock to refineries in the U.S. In order to accommodate these flows, the construction of additional transportation facilities would be required.

An array of tariffs was submitted for both the Edmonton to Sarnia and the Sarnia to Montreal systems. The tariffs reflected various throughputs and the respective capital and operating costs.

Saint John Project

The Province of New Brunswick submitted details of a 400 Mb/d potential oil terminal at Saint John, New Brunswick and pipeline to Portland, Maine to be connected to the existing Portland-Montreal pipeline system. It was submitted that this project would offer the lowest cost and minimum risk for the entry of foreign oil into Canada, and the transport southward of Arctic oil and gas. Several other alternatives were examined, but these were eliminated for economic or environmental reasons. In addition, it was proposed that oil storage in salt deposits located within 40 miles of Saint John could provide the lowest cost stategic oil storage in Canada suitable for pipeline distribution to Canada and the United States.

The Province of Nova Scotia also dealt with the financial aspects of a potential oil terminal at Saint John, New Brunswick. Its presentation included an economic study of various transportational modes for shipping oil to Montreal.

Additional financial material on a pipeline link between Saint John and Montreal was submitted by Kitimat.

Canso Project

Home presented a conceptual plan of a deep water trans-shipment terminal and salt-cavern oil storage at the Strait of Canso, Nova Scotia. It was contended that this project, in combination with trans-shipment to the Portland-Montreal pipeline, would add to Canada's security of supply and would be the most efficient system for oil importation and distribution for Canada.

Murphy and the Province of Nova Scotia supported a terminal and salt cavern oil storage at the Strait of Canso in conjunction with a Maritime-Quebec pipeline connection to Montreal. Financial studies of possible pipeline connections were submitted by both the Province of Nova Scotia and Kitimat. Nova Scotia studies were based on an assumed throughput to Montreal of 1250 Mb/d.

The Mayors and Wardens Committee, the Port Hawkesbury Board of Trade, and the Strait of Canso Industrial Development Authority all supported the Strait of Canso concept.

Bell Island Project

The Province of Newfoundland submitted a proposal related to a potential hydrocarbon-storage and trans-shipment-terminal facility at Bell Island, Newfoundland. This facility would consist of a year-round port capable of receiving ULCC's, and an oil storage facility located in an abandoned hematite iron-ore mine. It was contended that this project would provide strategic oil storage for Canada and the United States at a reasonable cost.

7.4 ECONOMIC AND FINANCIAL IMPLICATIONS

Several economic implications were suggested at the inquiry concerning the various possibilities for importing crude oil.

7.4.1 West Coast Options

Kitimat stated that its project would provide Canada with additional access to imported crude oil at little or no incremental cost to Canadians, since the majority of the costs would be borne by U.S. shippers.

Foothills and Kitimat both stated that a west coast option would extend the useful life and reduce unit transportation costs of existing Canadian oil pipelines. Kitimat stated that this would result in a benefit to consumers in all market areas served.

Kitimat argued that the west coast has a "distinct economic advantage" with regard to ocean transport. In the revised Schedule "B" of its submission, it provided estimates of tanker rates from the Persian Gulf to Kitimat and from the Persian Gulf to Portland, Maine. The former was $1.54 per barrel while the latter ranged from $2.05 to $2.47 per barrel.

Foothills and Kitimat both stated that a west coast option would facilitate oil exchanges between Canada and the United States. Kitimat stated that Alaskan oil could be exchanged for various types of Canadian crudes and that this would give both Canadian and United States refiners additional flexibility in crude mix.

Several submittors argued that a west coast option would have a more favourable effect on the marketing of heavy crude oil than would an east coast option. It was pointed out that an east coast port and associated facilities would eliminate Montreal as a market for Canadian heavy crude if the Sarnia to Montreal pipeline is reversed to supply offshore crude to Ontario markets. In addition, a reversal of the Sarnia to Montreal pipeline would make it possible to bring foreign heavy crudes into Ontario, which would mean an increase in competition among heavy crudes for the Ontario asphalt market. It was recognized that a west coast option might eliminate Canadian heavy crude oil exports to the Northern Tier refineries. PanCanadian Petroleum argued, however, that in the absence of a west coast option, the U.S. would likely have no economic alternative but to build an all-American line such as the proposed Northern Tier Pipeline from Port Angeles, Washington to Clearbrook, Minnesota. Such a pipeline could eliminate the U.S. Northern Tier as a market for Canadian heavy crude oil. PanCanadian recommended, however, that approval of any pipeline intended to serve the

United States Northern Tier markets should contain a condition requiring that Alaskan or offshore crudes not be allowed to displace surplus Canadian heavy crude oil in these historical markets.

A west coast option was also felt to improve security of supply. Hudson's Bay Oil and Gas argued that having facilities on both coasts would improve the security of the overall import system in the event of international supply disruptions.

Several arguments were presented in favour of or against a particular west coast option. Foothills stated that its projects presented both a "unique opportunity" to exploit an infrastructure of a gas pipeline, and a more environmentally acceptable means of transporting Alaska oil across Canada than any other project yet proposed. Trans Mountain argued that the advantage of using existing systems, both in economic and environmental terms, should not be overlooked. The Government of British Columbia suggested that any option that displaced domestic oil in the Vancouver market would not be in the best interests of Canada. It argued that, based upon transportation and refinery costs, B.C. benefits more from its access to domestic crude than either Ontario or Montreal. This view was supported by the Vancouver Board of Trade, Chevron Canada, and COFI.

There were also some submittors who felt that no west coast option was desirable. These submittors generally considered the east coast options to be more economical or the environmental risks surrounding the west coast options to be unacceptably high.

7.4.2 East Coast Options

Various submissions addressed the economic implications for the expansion of east coast port facilities. In particular, Nova Scotia and New Brunswick provided detailed cost estimates for a number of alternatives to transport oil to Montreal. Submittors also addressed the benefits of combining expanded import facilities with strategic storage, the economic issues relating to the balance of payments and regional economic development, and the environmental advantages and disadvantages of specific proposals.

With the exception of SCIDA, submittors generally agreed that unless import requirements were to increase above the current capacity of the Portland - Montreal pipeline, the continued use of existing facilities represented the most efficient use of resources.

For the numerous import cases presented by Nova Scotia, comparative figures for the facilities required for an assumed throughput of 1250 Mb/d to Montreal were presented for capital costs, operation costs, and total transportation costs. These total costs were estimated to be the average "door to door" cost per barrel in 1977 dollars over the life of a given project. It was assumed that there would be no differentials in crude price for a given source of supply (i.e., the F.O.B. price would be the same for each customer), and that those alternatives whose annual operation costs were a greater portion of total transportation costs would be more subject to inflation than those alternatives whose annual operation costs were a lesser portion of total transportation costs.

Based on four sources of supply, Nova Scotia concluded that the lowest-cost transportation alternatives for supplying imported crude to Montreal were:

Source	Port
North Sea	Saint John
Venezuela	Portland
Nigeria	Saint John
Gulf of Iran	Strait of Canso

The cost advantage for the Strait of Canso over Saint John, in the case of supply from the Gulf of Iran, was based on the assumption that costs per barrel for Saint John would increase faster than the same costs for Canso. This position was supported by data illustrating the effect of an eight percent rate of inflation in operating costs for the shipment and trans-shipment/pipeline phases for these two ports.

The Province of New Brunswick disputed these latter calculations and later filed total cost estimates using the same assumptions as Nova Scotia to illustrate that from the Gulf of Iran, Saint John was the least cost alternative.

Nova Scotia stated that factors besides transportation costs should weigh in the decision regarding the optimal choice of an import facility. It was stated that it would be less expensive to Canada to move oil through a Canadian port as there would be a reduction in foreign exchange outflow. In addition, import costs could be reduced by the construction of U.S.-Canadian strategic storage at the Strait of Canso, with a pipeline link to Montreal and a branch from this line to the United States.

From the point of view of regional development, Nova Scotia stated that the existence of a Canso-Montreal pipeline would do much to assist development of the local economy and oil-dependent industries would be attracted to the province.

With regard to environmental concerns, Nova Scotia submitted that an import facility located at the Strait of Canso would present the lowest environmental risk of all ports considered.

New Brunswick provided, as did Nova Scotia, total transportation costs per barrel for crude oil imported to Montreal. Costs per barrel in 1977 were provided for ocean shipping and marine terminal and pipeline charges. In addition to import facilities located at Saint John, Canso, and Portland, estimates were also provided for imports via Kitimat and Baie Comeau. All cases assumed pipeline connections with Montreal.

Based on an estimated throughput of 400 Mb/d by 1985, New Brunswick concluded that for sources of supply in the North Sea and Venezuela, the most economic alternative would be the use of existing facilities at Portland. For sources of supply in Nigeria, the Persian Gulf, and Indonesia, the lowest cost alternative involved VLCC imports to Saint John, and then pipeline movements either directly to Montreal or indirectly, by a pipeline connection with the Portland-Montreal pipeline.

New Brunswick stated that cost reductions could result if the import facility were combined with a strategic storage program, but that such a reduction should be regarded as a "bonus" and not a "base load". The Saint John site would have a considerably lower cost than a site at Canso for strategic storage since the pipeline distance to U.S. and Canadian markets is shorter by 250 miles.

New Brunswick rejected Nova Scotia's assertion that navigational risks for VLCC's were greater at Saint John than at the Strait of Canso. New Brunswick stated that "Canaport" in Saint John Harbour was the first facility in North America to accept VLCC's and that it was operating successfully.

Home Oil stated that on the basis of its supply and demand projections to 1995, the present capacity of the Portland-Montreal pipeline would be sufficient to supply requirements in the Montreal area. Home indicated, however, that as the dependence on crude oil from the Persian Gulf and Africa increased, a trans-shipment facility on the east coast to move these imports to Portland could be substituted for those facilities currently being utilized in the Caribbean.

Home stated that the trans-shipment segment of its proposal for Canso appeared to be less expensive than other East Coast ports of entry as new "grassroots" facilities would be required in most other areas. Additional advantages Home attributed to its proposal were that strategic storage could enhance security of supply for offshore crude and provide security for increased levels of crude oil exchange with the U.S.

Home also stated that those alternatives that limited imports to the Maritimes and Quebec would have a refinery cost advantage, since lower conversion costs would be required to accommodate imported crude than for refineries located further west.

The Government of Newfoundland and Labrador indicated that the Wabanex proposal for strategic storage could be less expensive than developing alternative storage sites solely for Canadian needs, and that such a project would lead to greater cooperation between Canada and the United States in energy-related matters. It was further stated that the use of part of the facility for trans-shipment purposes would result in significant savings for Canadian energy consumers in comparison to trans-shipment facilities currently being utilized in the Caribbean.

7.4.3 Arctic Projects

Neither Dome nor Panarctic discussed the economic advantages of transporting oil from the arctic to west coast or east coast ports.

Panarctic stated that Canso, Saint John, and Come-by-Chance could all handle a 200,000-ton tanker, and that any one of these three ports would be suitable.

Dome suggested that oil from the north could be transported either to Eastern Canada or through the Bering Strait to Western Canada, but it did not discuss any particular port of entry.

7.4.4 Interprovincial Pipeline

Interprovincial stated that unused capacity currently exists in its pipeline. It also pointed out that capacity could be added at a significantly lower cost than that which would have to be incurred to construct a new pipeline. Interprovincial stated that while it could see certain advantages to a west coast option that would transport oil to the United States, its facilities could also be integrated with an east coast option.

CHAPTER 8

DETERMINATION OF EXPORT VOLUMES

8.1 INTRODUCTION

The Board, in its Order, did not specifically request submittors to comment on the appropriateness of the existing export licensing procedures for light and heavy crude oils and refined petroleum products. The procedures were, nevertheless, discussed in many briefs.

Since 1 January 1975, the Board has determined annually the exportable surplus of crude oil using a protection procedure often referred to as the "t/10" formula. The principle underlying this formula is that if forecasts of supply and demand for indigenous feedstocks indicate that reasonably foreseeable Canadian requirements are not protected for at least 10 years, exports will be phased out. The formula also ensures that demand conservation efforts in Canada will not result in increased exports.

Under this program, exports of crude oil and equivalent were reduced from 911 Mb/d in 1974 to 707 Mb/d in 1975 and 465 Mb/d in 1976. Commencing 1 January 1977, the Board modified the application of its protection formula in order to stimulate the development of Canada's heavy crude oil resources. The same formula was employed, but it was applied separately to heavy crude oil and to light crude oil supply-demand balances. Total crude oil exports were reduced to 270 Mb/d in 1977 and are expected to average about 175 Mb/d in 1978.

Mathematically, the Board's protection procedure can be expressed as follows:

$$E = \left[P - (D + C)\right] \frac{t}{10}$$

Where:

E is the average volume in Mb/d available for export licensing for the year for which the determination is made.

P is the forecast average potential producibility of crude oil and equivalent in Mb/d for the year for which the determination is made.

D is the forecast average requirements for Canadian use in Mb/d of indigenous crude oil and equivalent for the year for which the determination is made.

C is the forecast total increase that would have occurred in requirements for indigenous crude oil and equivalent in Mb/d if conservation measures since 1972 had not been effective.

t is the time during which supply is forecast to exceed Canadian requirements, from 1 January of the year for which the determination is made, expressed to the nearest tenth of a year, and extended to a maximum of ten years.

Canadian requirements protected in the past have included all feedstock requirements west of the Ottawa Valley plus 250 Mb/d for the Montreal market. At the present time, however, consideration is being given by the government to increasing deliveries to Montreal. To bracket the protection requirements, the Board has made calculations based on aggregate movements of light and heavy crude oil to Montreal of 250 Mb/d and 350 Mb/d.

8.2 LIGHT CRUDE OIL

8.2.1 Views of Submittors

The submittors' views regarding the determination of light crude oil exports addressed generally three areas of concern:

- the current high level of shut-in capacity of light oil,
- the adequacy of the Board's protection procedure,
- the special import dependency of certain United States refineries on Canadian crude oil.

The current level of shut-in production capacity of light oil in Western Canada was estimated to be about 400 Mb/d by CPA and by HBOG. Several submittors, including CPA, Amoco, Canadian Hidrogas, and HBOG, recommended short-term exports to provide the market incentive and cash flow necessary to develop additional supplies.

Several submittors commented on the adequacy of the Board's current formula. Ontario said that the Board's 10-year standard is not long enough and suggested that a 30-year standard would be more appropriate. The CRND wanted all oil exports phased out by 1980. The UFAWU submitted that the coming on stream of synthetic crude oil and heavy oil plants should not result in increased exports. Amoco submitted that if use of the export formula were to be continued, a demand projection should be used based on current and future economic conditions, not one that assumed that energy prices would remain constant in real terms at the levels which prevailed at the end of 1972.

The Government of the United States, United States Senator Paul Hatfield, and Congressman Max Baucus stressed the dependency of Montana refineries on Canadian crude oil and indicated their desire for exports to continue.

8.2.2 Views of the Board

The Board has stated previously that as exports of light crude oil approached zero, adjustments to its broad policy of phasing out such exports would likely be necessary. Operational constraints and surpluses of specialty feedstocks could necessitate such adjustments. While the formula remains the basic tool for assessing the exportable surplus, the Board believes that light crude oil exports have declined to such a relatively low level (currently 55 Mb/d) that factors other than those accounted for by the formula should be major determinants in issuing export licences.

Using the export formula, the volumes of light crude oil and equivalent that would be surplus for 1979 are:

Assuming
250 Mb/d to Montreal

$$E = \left[P - (D + C)\right] \frac{t}{10}$$

$$E = \left[1603 - (1141 + 72)\right] \frac{3.3}{10}$$

$$E = 129 \text{ Mb/d}$$

Assuming
350 Mb/d to Montreal*

$$E = \left[P - (D + C)\right] \frac{t}{10}$$

$$E = \left[1603 - (1231 + 72)\right] \frac{2.6}{10}$$

$$E = 78 \text{ Mb/d}$$

* The 100 Mb/d crude oil requirements difference between the cases is assumed, for 1979, to be composed of 90 Mb/d of light crude oil and 10 Mb/d of heavy crude oil. See Appendix M for details.

The calculations can be repeated for subsequent years to show the effect the protection procedure might have on exports in the future and how long the supply-demand intersection can be delayed. For each year considered, a new potential producibility projection must be constructed to account for the carry-forward effect of production at rates lower than capacity. The effect of this carry-forward is illustrated in Figures 8-1 and 8-2.

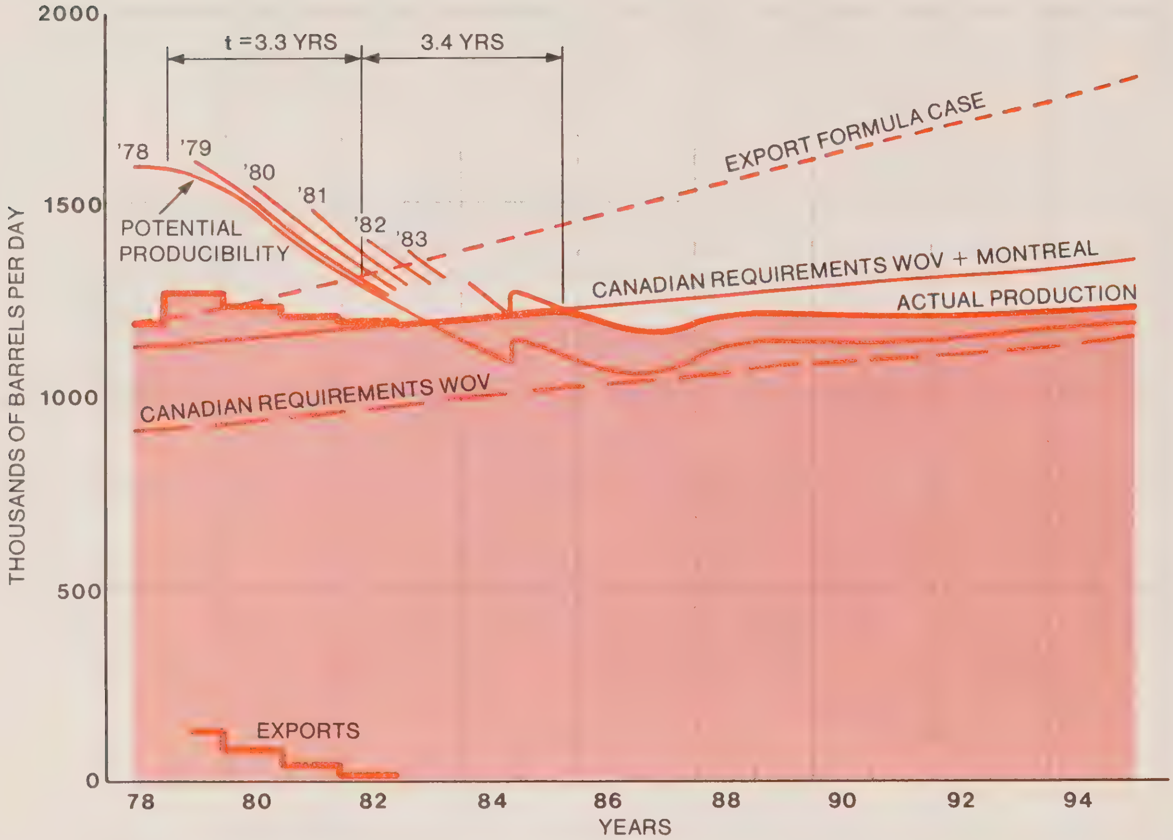


Figure 8-1 **CALCULATION OF ALLOWABLE EXPORTS OF LIGHT CRUDE OIL AND EQUIVALENT 250 Mb/d to Montreal Case**

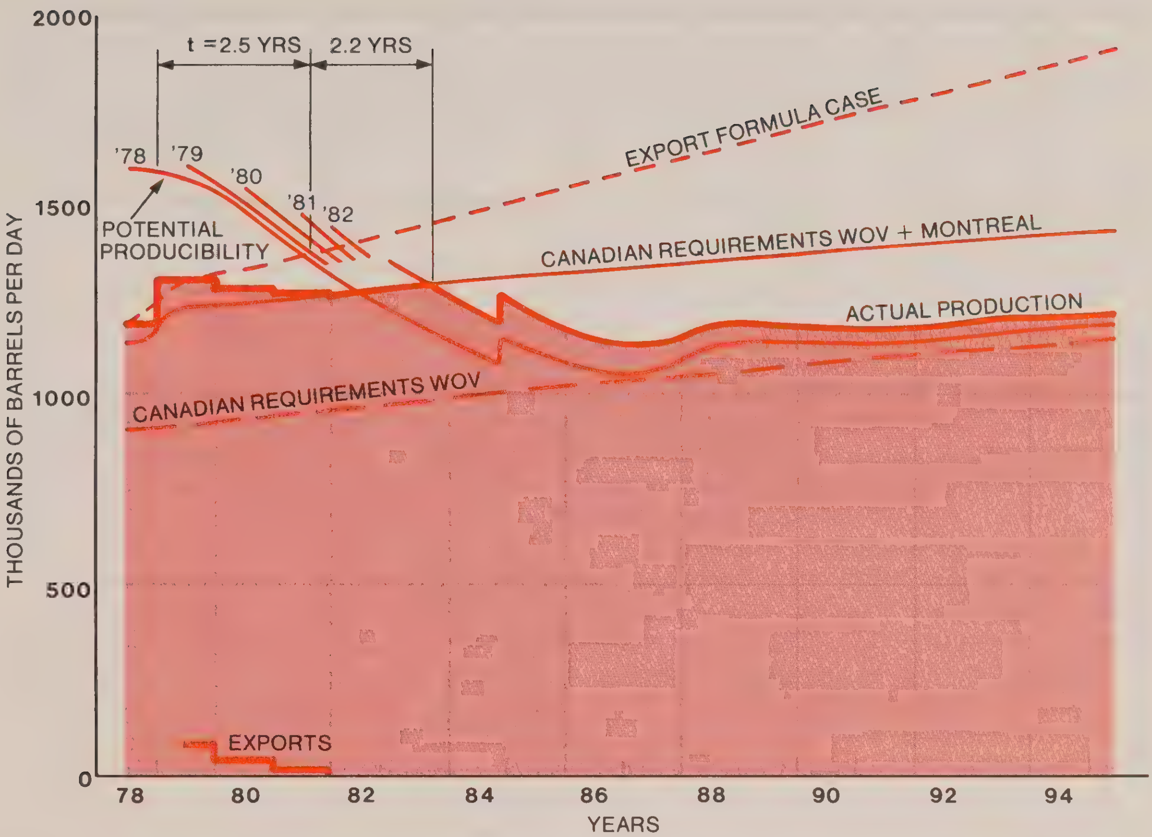


Figure 8-2 **CALCULATION OF ALLOWABLE EXPORTS OF LIGHT CRUDE OIL AND EQUIVALENT**
350 Mb/d to Montreal Case

Table 8-1 shows what the future allowable export levels of light crude oil and equivalent would be, using this method.

Table 8 - 1
ALLOWABLE EXPORTS
OF LIGHT CRUDE OIL AND EQUIVALENT

(Mb/d)

Year	Assuming 250 Mb/d to Montreal	Assuming 350 Mb/d to Montreal
1979	129	78
1980	75	39
1981	36	11
1982	10	0

Decreasing exports in each of the years as shown above would be approximately equivalent to maintaining a flat three-year average export of 80 Mb/d assuming 250 Mb/d to Montreal, or 43 Mb/d with 350 Mb/d to Montreal.

In the interest of giving Canadian producers of light oil a clearer outlook as to likely export levels, the Board sees merit in licensing exports at a constant rate for the period 1979 to 1981 inclusive. Given the uncertainties of levels of shipments to Montreal and the range of uncertainties in the supply and demand forecasts themselves, the Board believes that a continuation of the 1978 level of light crude oil licences, at 55 Mb/d, would be reasonable. The Board notes that fixing the level of exports for the next three years should also provide a more certain projection for exports of light crude thus assisting the Northern Tier refiners in making alternative supply arrangements. It is anticipated that after 1981, exports of light crude oil would cease except for oil that is exported under exchange arrangements and certain volumes which because of grade or geographic location are limited to use by customers in the United States and subject of course to any unforseen developments in Canadian supply and demand.

8.3 HEAVY CRUDE OIL

8.3.1 Views of Submittors

There was wide support for the position that a curtailment at this time of the exports of surplus heavy crude would adversely affect producers of heavy crude oil. PanCanadian and Pacific stated that requirements for feedstock for planned upgrading plants should be excluded from surplus calculations to avoid reducing exports and revenues to producers and thus possibly curtailing investments needed to develop new recovery technology. Amoco

suggested that the incentive of producing at capacity would accelerate the rate of discovery and development of additional supplies. Essentially the same position was taken by the CPA, Dome, and Hidrogas. Murphy stated that a lack of markets leads to prorationing, which defers exploration and affects the progress of pilot recovery projects to a great degree. Husky suggested that the major problems encountered heretofore by heavy oil producers have been depressed prices and lack of markets.

8.3.2 Views of the Board

There was ample evidence attesting to the promise of heavy crude oil development in Canada's energy future. It is the Board's view that Canada would benefit by adopting policies that would stimulate adequate markets to foster the development of enhanced recovery techniques, especially for Lloydminster-type crudes. Such development is anticipated to be considerably more costly than for conventional production, but in the Board's opinion its attainment is central to ultimate utilization of the full potential of Lloydminster-type reserves. Economic tertiary production is far from assured and the pace of activity will be dependent upon the economic circumstances of producers. Producers will not continue investing unless there is an assurance that markets will exist for the resources that they find and develop.

The Board appreciates the argument that domestic markets represent an alternative to exports. However, Canadian refiners are limited in their ability to process heavy crudes and would require an incentive to improve that ability. A reduction in the price of heavy crude relative to light crude might improve refinery economics, but the reduced revenues to heavy crude producers would not be conducive to the timely development of expensive recovery facilities.

For the purposes of the determination of heavy crude surpluses, the Board intends to exclude from Canadian demand the feedstock required for an upgrading plant until such a plant is in operation. This will allow producers to maintain levels of production, by virtue of exports to the Northern Tier refineries, until the heavy crude is actually required by the upgrading plant.

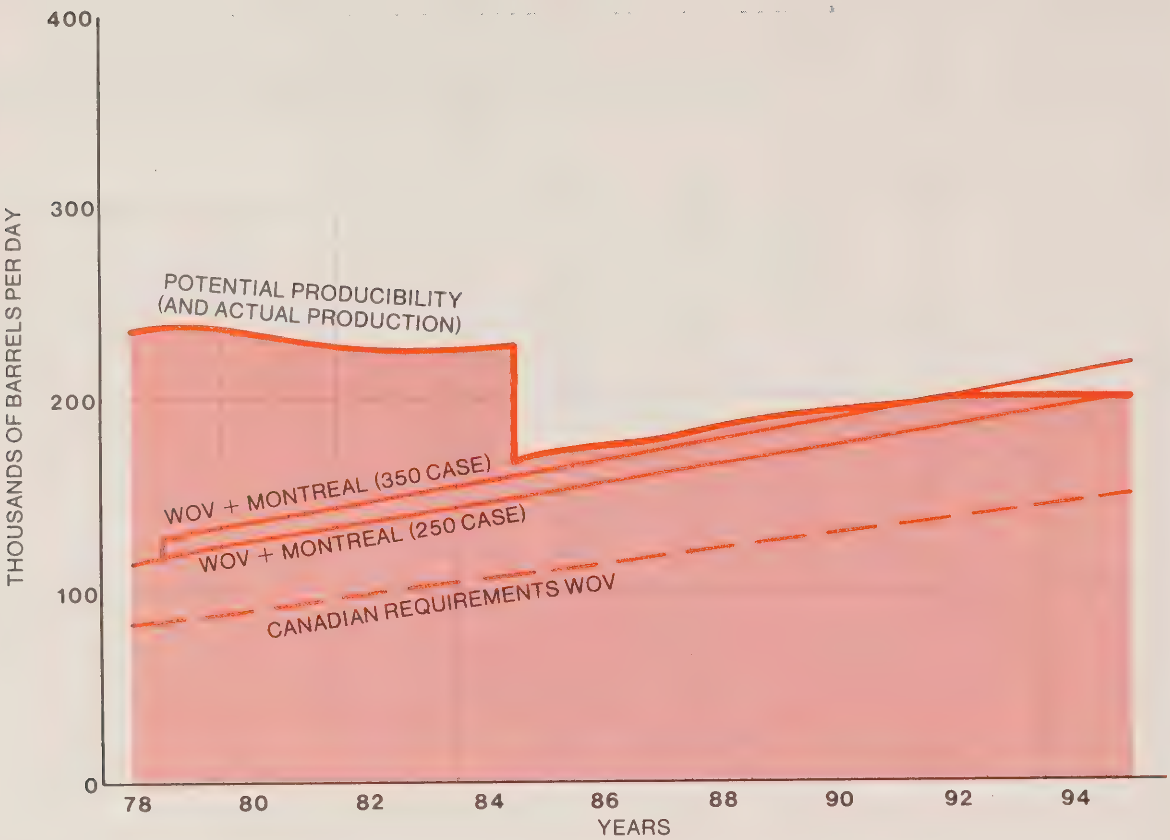


Figure 8-3 **CALCULATION OF ALLOWABLE EXPORTS OF HEAVY CRUDE OIL**

The Board's supply-demand balance for heavy crude oil is shown in Figure 8-3. Using parameters determined from this figure, the calculation of allowable exports for 1979 is:

Assuming <u>250 Mb/d to Montreal</u>	Assuming <u>350 Mb/d to Montreal</u>
E = 239 - (122 + 0) x 1*	E = 239 - (132 + 0) x 1*
E = 117 Mb/d	E = 107 Mb/d

$^*\frac{t}{10}$ is set to 1 when t is greater than 10 years

The values 117 Mb/d and 107 Mb/d should be viewed only as indications of the volumes of heavy crude oil that will be available for export during 1979. This is because, with t exceeding 10 years in the Board's export control formula, the only restriction placed on exports is that feedstock requirements of Canadian refineries must be met first. The remainder of productive capacity is then available for export. The limiting values of exports will thus depend on actual productive capacity and Canadian requirements determined on a quarterly basis. Levels of exports beyond 1979 will be determined by the rate of heavy oil development, the construction of upgrading facilities, and, of course, the Canadian demand for asphalt.

8.4 REFINED PETROLEUM PRODUCTS

8.4.1 Views of Submittors

The submittors were in general agreement that petroleum products surplus to Canadian requirements should be exported. Texaco advocated that surplus energy supplies should be upgraded to the maximum extent possible before exporting and that potential exports should not be discouraged by high export charges or stringent regulatory procedures. Others, including Shell, stated that exports should be encouraged in the interests of achieving fuel substitution objectives, optimizing utilization of existing refineries, and contributing positively to Canada's balance of payments. Sun Oil suggested that currently under-employed refinery capacity in Canada should be utilized to meet product demands in adjacent U.S. markets by refining U.S. owned crude oil. Gulf and Imperial took the position that, with the exception of the U.S. mid-west, it would be difficult for Canadian refiners to compete with offshore supplies in export markets. Union Carbide cautioned that although the export market was large, it was also finite.

More specifically, it was the general view that if natural gas was to be encouraged to penetrate the Eastern Canadian market, the heavy fuel oil being displaced by natural gas must be exported. Dow submitted that exports of surplus heavy fuel oil should be permitted, but its export price should not be lower than the cost of purchasing energy in the form of imported crude. Further testimony dealing with potential means of reducing the surplus such as upgrading the heavy fuel oil and increased use of naphtha feedstock for petrochemical operations have been discussed under Refinery Flexibility in Chapter 5.

8.4.2 Views of the Board

The Board is aware that Canadian refiners face an array of problems. The lower-than-anticipated growth in petroleum product demand in Canada, and the limited opportunity afforded refiners to export products have certainly contributed to the present surplus refining capacity. Also, variations of feedstock supply for refineries and significant increases in the domestic market shares for natural gas would likely complicate the ability of the refining industry to supply the changing mix of product requirements.

In that area of Canada where refineries process foreign origin crude oil, the Board will continue to recognize in its export licensing approach that, at least in part, refinery capacity was constructed to serve the export market. However, the viability of these refiners is still heavily dependent upon their ability to secure export markets. Such dependency could become even greater if natural gas penetration were to occur in Eastern Canada. Export markets for any displaced products, heavy fuel oil in particular, would have to be developed to prevent refiners from suffering serious financial hardships.

In that area of Canada processing indigenous crude oil, the Board sees it as fundamental that as Canada continues to husband its diminishing resources of crude oil, the products made from that crude oil must also be conserved. It follows that controls on product exports should continue, and that such exports be regulated in a manner compatible with the overall objective of achieving energy self-reliance. While keeping that objective clearly before it, the Board will assess each application it receives for a licence to export petroleum products in the light of the refining and marketing conditions prevailing at the time.

If refiners with adequate spare capacity can arrange to refine United States or overseas crude to supply products for the U.S. market, as suggested by some submittors, the Board believes that this should be encouraged.

Energy, Mines and Resources Canada | Energie, Mines et Ressources Canada

Minister | Ministre

APPENDIX A

Ottawa K1A OA7 Ontario
January 16th, 1978.

BY HAND

Mr. J. Stabback
Chairman
National Energy Board
473 Albert Street
Ottawa, Ontario
K1A OE5

Dear Mr. Stabback:

The exposure of Eastern Canada to possible medium or long term shortages of imported oil is well recognized and considerable effort has been, and is being made to reduce our vulnerability under such conditions. The extension of the IPL pipeline to Montreal and studies of greater natural gas penetration and greater emergency oil storage are examples of these efforts.

Under some projections of domestic oil production however, we may be faced with a difficult decision as to how to allocate inadequate supplies between eastern and western market areas. Not only might the reversal of the IPL extension be required, but also a very significant reduction in the volumes available to the Trans Mountain Pipeline to British Columbia markets. This is a concern which the Honourable Jack Davis, the British Columbia Energy Minister has raised with me on a number of occasions.

Under the provisions of Section 22 (2) of the National Energy Board Act I am hereby requesting the Board to investigate and report to me on a range of possible oil supply situations over the course of the next 10 to 15 years and the import dependency which might develop for British Columbia consumers as well as for eastern Canadians. Where significant imports are required your views on the size, location and timing of petroleum ports of entry are requested.

I would appreciate your views on when your report could be expected.

Yours sincerely,

Alastair Gillespie

NATIONAL ENERGY BOARD — CANADA — OFFICE NATIONAL DE L'ÉNERGIE

ORDER NO. OHR-1-78

IN THE MATTER OF the National Energy Board Act and Sections 22(2) and 24 thereof; and

IN THE MATTER OF an inquiry, hearing and determination of the supply of Canadian oil, the domestic demand for oil and for indigenous feedstocks, the import dependency of Eastern Canada and potential demand for imported oil in British Columbia and other parts of Canada presently served by indigenous oil, and related matters; under File Number 1722-9-3.

BEFORE the Board on Thursday, the 26th day of January, 1978.

WHEREAS by letter dated the 16th day of January, 1978, the Minister of Energy, Mines and Resources, has requested the Board to investigate and report on a range of possible oil supply situations in Canada over the course of the next 10 to 15 years and the import dependency which might develop for British Columbia consumers as well as for Eastern Canadians;

AND WHEREAS the Minister has also requested, where significant imports are required, the Board's views on the size, location of and time when new or expanded oil ports would be required;

AND WHEREAS the Board finds it advisable to hold a public inquiry to afford an opportunity for those in the energy sector, the provinces and the general public who have an interest in such subjects to be heard;

IT IS ORDERED THAT

1. A public inquiry shall be held in the Clerks Office, Court House, 611 4th Street, S.W., in the City of Calgary in the Province of Alberta commencing on the 24th day of May, 1978, at 9:30 a.m. local time and at such other times and places in such of the Cities of Vancouver in the Province of British Columbia; Ottawa in the Province of Ontario; Quebec City in the Province of Quebec and Halifax in the Province of Nova Scotia as the Board shall determine having regard to the number of persons who have filed written submissions pursuant to the Board's Notice of Public Inquiry of the 26th day of January, 1978, wishing to be heard in such cities.

The inquiry will be conducted in either of the official languages and simultaneous interpretation facilities will be provided in both Ottawa and Quebec City. These facilities will also be provided in other locations if it appears from the written submissions filed with the Board that both official languages will be used in those locations.

2. The purpose of the inquiry referred to in paragraph 1 is to obtain facts and information by means of viva voce and written evidence, statements of position, and where necessary, opinions from those persons who have filed written submissions with the Board in response to the Board's Notice of Public Inquiry dated the 26th day of January, 1978, subject to those facts and information being relevant to the matters set out in paragraph 3 of this Order, provided that such persons in adducing, making or placing before the Board evidence, statements of position, or opinions, or in electing not to do so, in whole or in part, shall be free to present their case in their own manner.

3. The subject matter of the inquiry to which all facts and information shall be relevant is, and the same is declared to be:

(1) Within the context of a review of supply and demand for all forms of energy, the base case estimates (as defined in the Outline for Submissions) for oil during the period ending in 1995 of:

   (a) reserves and producibility of Canadian oil;
   (b) domestic demand; and
   (c) the need for foreign oil.

(2) Estimates of the extent to which oil can be replaced by other energy forms in the market place, and discussion of:

   (a) potential impacts of such replacement; and
   (b) the pricing policies, and other considerations which would affect substitution;

(3) Further potential for reducing demand for oil through demand conservation not included in 1(b) above;

(4) Further potential for augmenting the supply of oil not included in 1(a) above; and

(5) Review of Canada's current capability to import oil and the timing, costs, location and type of transporation and ancillary facilities which may be needed in the future to increase this capability, and the way in which particular markets might best be served in future by foreign oil.

Further particulars in relation to certain of the above matters are set out in a document entitled "Outline for Submissions" which is attached to and forms part of this Order.

4. Persons who wish to make a submission to the Board on those matters set out in paragraph 3 herein, or to adduce, make or place before the Board, facts and information by means of evidence, statements of position or opinions, shall, unless the Board otherwise orders,

(a) state in their submission the official language in which, and which of the cities enumerated in paragraph 1 hereof, they wish to be heard;

(b) file and serve, on or before the 28th day of April, 1978, upon the Secretary of the Board thirty-five (35) copies of their written submission in either of the official languages;

(c) serve, on or before the 8th day of May, 1978, upon each other person who has filed a written submission with the Board in response to the Board's Notice of Hearing, dated the 26th day of January 1978, as determined according to a list to be provided from time to time to all submittors by the Secretary of the Board, a copy of their written submission, and shall file proof of service thereof with the Board;

(d) not be entitled to introduce into evidence by viva voce or written evidence, or otherwise any subject matter beyond the scope of the subject matter of this hearing;

(e) present witnesses who can answer to the matters contained in his written submission filed with the Board in cross-examination by Board Counsel and by other such persons in accordance with sub-paragraph (f); and

(f) be entitled to cross-examine witnesses of other such persons on the matters contained in their written submissions, provided such cross-examination and such matters are relevant to the matters set out in paragraph 3 herein.

5. Submittors who wish to make a supplemental written submission at the close of the inquiry be and the same are hereby directed to submit, within one week of the close of the hearing, such written supplemental submission, which such written supplemental submission shall be relevant to the matters set out in paragraph 3 herein.

DATED at the City of Ottawa, in the Province of Ontario, this 26th day of January, 1978.

NATIONAL ENERGY BOARD

G.G. Michaud
for Brian H. Whittle,
Secretary

NOTICE OF PUBLIC HEARING

TAKE NOTICE THAT the National Energy Board's Public Inquiry into the supply of Canadian oil, the domestic demand for oil and for indigenous feedstocks, the import dependency of Eastern Canada and potential demand for imported oil in British Columbia and other parts of Canada presently served by indigenous oil, and related matters, convened by Order No. OHR-1-78 shall be held in the Clerks Office, Court House, 611 4th Street, S.W., in the city of Calgary in the province of Alberta commencing at 9:30 a.m. local time on the 24th day of May, 1978, and at such other times and places in such of the cities of Vancouver in the province of British Columbia; Ottawa in the province of Ontario; Quebec City in the province of Quebec and Halifax in the province of Nova Scotia as the Board may determine having regard to the number of persons who have filed written submissions.

The inquiry will be conducted in either of the official languages and simultaneous interpretation facilities will be provided in both Ottawa and Quebec City. These facilities will also be provided in other locations if it appears from the written submissions filed with the Board that both official languages will be used in those locations.

Interested parties may obtain a copy of the Order including the Outline for Submissions by writing to the Secretary of the Board at the Trebla Building, 473 Albert Street, Ottawa, Ontario, K1A 0E5 or by telephoning 613-992-5506.

DATED at the City of Ottawa, in the Province of Ontario, this 26th day of January, 1978.

NATIONAL ENERGY BOARD

"Brian H. Whittle"
Brian H. Whittle,
Secretary.

OUTLINE FOR SUBMISSIONS

Submittors are encouraged to use, where applicable, the following outline in the preparation of material. Those wishing to provide the Board with supply and demand estimates are requested to prepare a "base case" representing the levels of supply and demand which in their opinion are most realistic. The supply and demand categories outlined are based on the principles and procedures suggested at the Board's 1974 hearing in the matter of the exportation of oil which also formed the basis for the 1975 and 1976 hearings on Canadian oil supply and requirements.

Questions on this outline should be directed to the following members of the Board staff for the matters indicated:

oil supply	-	K.W. Vollman, Engineering Branch, Telephone Number (613) 996-2344
oil demand	-	N.E. MacMurchy, Economics Branch, Telephone Number (613) 996-2225
oil transportation facilities	-	T.S. Shwed, Engineering Branch, Telephone Number (613) 996-3487

1. RESERVES AND PRODUCIBILITY OF CANADIAN OIL

Forecasts with respect to supply should present base case estimates of reserves and of the average annual ability to produce Canadian crude oil and equivalent, unrestricted by demand, by province or territory for the period 1978-1995 for each of the following categories:

(i) conventional crude oil from

(a) established reserves at 1 January 1978

(b) reserves additions to existing reservoirs

(c) new discoveries in existing producing regions;

(ii) pentanes plus from

(a) established reserves at 1 January 1978

(b) reserves additions;

(iii) oil recoverable from oil sands by

(a) surface mining

(b) in situ techniques; and

(iv) frontier crude oil and equivalent.

As in the case of its February 1977 oil report, the Board intends to publish separate supply determinations for light and for heavy crude oils. Accordingly, submittors are encouraged to use the above categories for each of a light and a heavy crude oil supply forecast.

Submittors may choose to submit a range of forecasts for each category to indicate the uncertainty regarding geological, technological and economic assumptions. However, in each instance the submittor is encouraged to identify the forecast which he perceives as the most likely case.

Submissions should outline the technique used to forecast each supply category and all major assumptions should be stated. Grouping of categories is discouraged because it makes comparison of forecasts difficult.

With respect to i(a) above the Board suggests that a pool by pool forecasting technique be used by those submittors who have access to the requisite data base. In order to assist the Board in assessing the supply-demand balance for various types of crude, it is suggested that submittors present subtotals by oil grade using the pool definitions of light and heavy crude oil given in Appendix 1. The Board expects that companies which are operators or major participants in any of the pools listed in Appendix 1 will submit a producibility forecast for these pools. While this list is intended to serve as a guideline, submittors may wish to provide data on alternative or additional pools where they feel this would improve the accuracy of the forecast.

The Board requests that all pool producibility data be submitted in the format illustrated in Appendix 2. However, it is not the Board's intention to limit data to those requested in Appendix 2. Submittors are encouraged to submit any additional data, such as decline curve analyses, economic limits, reservoir model studies and graphic performance analyses which they feel are pertinent to the matter of determining supply.

The following guidance is offered to assist submittors in completing Appendix 2.

Section A

Normally, field pools will be identified by completing the spaces marked "FIELD" and "POOL". The space "UNIT" will be left blank except for:

- cases listed in Appendix 1 where a unit, voluntary unit, or non-unit grouping of wells is to be studied; and

- cases in which the submittor may wish to provide a single producibility forecast for a pool, but may wish to provide reservoir data (e.g., recovery factors) on a unit basis. In these cases the submittor would use as many forms as required for the reservoir data, with only the first form in the series containing a pool producibility forecast.

Section B

In cases where the submittor has adopted "proved" and "probable" reserves definitions, the producibility forecast should be in respect of proved reserves. The producibility forecast should include production expected in respect of development programs which are contemplated with a high degree of certainty. Producibility is defined as the estimated average annual ability to produce, unrestricted by demand but restricted by reservoir performance, well density and well capacity, oil sands mining capacity and field processing capacity, that could be achieved on 90 days' notice.

Section C

Reservoir data should also relate to established or proved reserves. The Board is requesting these data to form a basis for comparing different producibility forecasts.

Section D

Information provided in Section D will assist the Board in assessing the potential for reserves additions from existing pools through infill drilling or improved recovery. Projected reserves additions should be based on the submittor's view of what will be technologically feasible under present and anticipated economic conditions.

With respect to i (b) and i (c) submittors are encouraged to detail reserves additions by recovery mechanism and geologic horizon with perhaps some additional consideration to ranges of reasonable estimates, and division by geologic province. It would be helpful if major potential producing horizons within the several geologic systems were identified. Assumptions regarding price, technology and lead times should be clearly stated.

Because of differing opinions encountered in previous hearings, the Board would appreciate receiving as much detail and elaboration with respect to i (b) and i (c) as possible to assist it in examining this important aspect of supply.

With respect to ii (a) the Board suggests that a forecasting technique based on individual gas processing plants be used by those submittors who have access to the requisite data.

The Board intends to base its forecast of pentanes plus supply on the evidence received including evidence on individual gas processing plants. A list of plants which the Board intends to review in detail is attached as Appendix 3.

The Board expects that companies which are operators of or major participants in any of these plants will submit a production forecast. This list is intended as a guide and submittors may wish to provide data on plants not listed in Appendix 3.

The Board requests that all plant production data be submitted in a format illustrated in Appendix 4. In order to clarify some of the assumptions inherent in a production forecast for pentanes plus the Board would appreciate receiving supporting data where available such as: product yields as a function of pool reservoir pressure, anticipated production rates and product yields in cycling schemes. Operators of a plant producing NGL mix should provide a forecast of NGL mix production accompanied by a percentage breakdown by component of total mix.

With respect to ii (b) submittors are requested to state clearly assumptions regarding annual gas reserves additions, annual production rates from reserves additions and pentanes plus yields.

II. DOMESTIC DEMAND

To place Canadian demand for oil in a total energy context, submittors are encouraged to present estimates of oil demand using a total energy-forecast approach. Submittors using such an approach are requested to provide a breakdown of Canadian energy demand by energy type including renewable energy. In order that comparative evaluations of the submitted oil forecasts can be made, all submittors are requested to make explicit the basic forecast assumptions such as economic growth, population growth, relative prices of various energy types, market shares, and expansion of energy types into geographic areas not presently using that energy form.

The forecasts of total market sales of refined petroleum products should be adjusted for industry use and loss, exports and imports. Regional forecasts should also be adjusted for product transfers. The separate contribution of butanes of gas plant origin to oil product supply has also to be distinguished, together with the proportion, where applicable, of foreign origin oil in total refinery runs. Submittors should provide a quantitative reconciliation of the respective forecasts of product sales and feedstock requirements in the format illustrated in Appendix 5.

All forecasts of oil demand should be expressed in thousands of barrels per day and should be accompanied by actual data for one year or more.

Submittors may choose to submit a range of forecasts to indicate the uncertainty regarding economic and other assumptions. However, in each instance submittors are encouraged to identify their base case i.e. the forecast which they perceive to be the most likely case.

III. PRODUCT SALES

The suggested level of detail for estimates of total market product sales is as follows:

> Forecast Period Demand, Actuals and estimates for 1975, 1976, 1977, 1978, 1979, 1980, 1985, 1990, and 1995.

GEOGRAPHIC AREAS

Atlantic

Quebec

Ontario

Manitoba

Saskatchewan

Alberta

British Columbia

Yukon and Northwest Territories

Total Canada

Ottawa Valley (these estimates should also be included in the total Ontario forecast)

East of the Ottawa Valley line

West of the Ottawa Valley line

PRODUCT CATEGORIES

Motor Gasolines	As described in Statistics Canada, Publication 45-208
Light Fuel Oil, Kerosene, Stove Oil	
Diesel Fuel Oil	
Heavy Fuel Oil	

Petrochemical Feedstock - those products intended for petrochemical processing that are manufactured in oil refining operations (including gases and petrochemical naphtha).

Other products

Total products

MARKET SECTOR DEMAND FOR OIL PRODUCTS

Those submittors whose forecast approach permits them to break-out estimates of oil demand by market sector are asked to provide information on classes of end-use as follows:

- residential
- commercial
- industrial
- thermal generation of electricity
- transportation - air
  road
  rail
  marine
- petrochemical feedstocks
- others

A clear description of the criteria used should be given for each sector.

OIL CONSERVATION

Submittors who have prepared a base case forecast will have included the effects of some conservation measures. 'Conservation measures' embrace:

- those programmes designed specifically to reduce oil demand, and

- those policies, whether general or specific, which may have a bearing on the consumption, conservation and price of any or all energy forms, and which may have a direct or indirect impact on oil demand.

The Board would like to know what submittors included for conservation in determining domestic demand in their base case. In addition, submittors are also encouraged to comment on and quantify any additional reductions in demand, by product category, resulting from conservation measures which, though feasible, are not anticipated to occur during the forecast period.

REPLACEMENT OF OIL BY OTHER ENERGY FORMS

Submittors providing estimates of the extent to which oil can be replaced by other energy forms in the market place should, if possible, provide estimates of the quantities of

each energy type that are projected to replace oil - that is natural gas, coal, electricity, and renewable energy. Where possible, the types and quantities of the various grades of petroleum products, and source of any electricity projected to displace oil should be specified.

Where estimates of the extent to which oil can be replaced by other energy forms have been derived by varying assumptions used in the forecasts developed in response to part (1) of paragraph 3 of the Inquiry Order, it is requested that a clear description be provided of the manner and degree in which each assumption was varied.

Submittors should provide information on the impact of replacement of oil with other energy forms.

A possible means of replacing oil is to expand natural gas use. To assist the Board in the assessment of the extent to which natural gas has a potential to displace oil, submittors are requested to submit estimates of:

(1) The extent to which oil, by product category, would, over the forecast period, lose market share at the expense of gas if natural gas for utilities supplied by TransCanada PipeLines was provided at a Toronto city-gate price that increased in a manner as to maintain the present 85 per cent of parity value with crude oil (refinery gate) at Toronto.

(2) Estimates of the effect on demand for oil in Canada, by product category, of specific changes, say, for example, variations in the ratio of the price of natural gas to crude oil reflecting changes of 5 per cent from the present base of 85 per cent.

Feedstock Requirements

Submittors are requested to provide a breakdown of feedstock requirements and a reconcilation of total market product sales as shown in Appendix 5. The Board expects that some submittors will have more than one crude oil demand estimate during the forecast period to reflect their views on the potential replacement of oil by other energy forms and by conservation as discussed in the preceding sections. However, the Board requests that submittors clearly identify their base case estimates.

Forecast Period Demand, Actuals and Estimates for 1975, 1976, 1977, 1978, 1979, 1980, 1985, 1990, and 1995.

Area: East of Ottawa Valley Line
West of Ottawa Valley Line
Total Canada

Feedstock Type: Canadian - Heavy crude oil (i.e. Lloydminster Blend, Wainwright, Viking-Kinsella, Chauvin, Fosterton, Bow River, Smiley Coleville, Midale Weyburn and other streams less than 25° API).

- Segregated Pentanes Plus
- Synthetic Crude Oil
- Other light and medium (including light and medium imported under exchange).

Foreign

Submittors are requested to estimate the volume and type of imports, exports and transfers of petroleum products. The separate contibution of butanes of gas plant origin to oil product supply should also be distinguished together with the proportion of foreign oil in total refinery runs.

REFINERY FLEXIBILITY AND UPGRADING

Submittors are requested to provide information including cost estimates and opinion on the following items:

(i) the flexibility of existing refineries to process the various grades of crude oil available in a manner that would minimize petroleum product surpluses;

(ii) the need for new or modified facilities in Canada to process synthetic crude oil (includes material from oil sands and heavy crude oil upgrading plants) and to upgrade heavy fuel oil so that oil supply surpluses would be minimized; and

(iii) the need for facilities to upgrade heavy crude oil into lighter feedstocks.

The Board requests that submittors provide all relevant information and the assumptions used, and the costs associated with the matters outlined in (ii) and (iii) above in constant 1977 dollars.

PORTS OF ENTRY AND OIL PIPELINE FACILITIES

Where a submittor concludes that new oil import facilities will be required, the Board requests relevant information on potential ports of entry and oil pipeline facilities. The Board requests, without restricting the submittors, that the following scenarios be presented:

(a) ports of entry on the East Coast;
(b) ports of entry on the West Coast; and
(c) ports of entry on both the East and West Coasts.

In respect of each scenario, the Board suggests that each submission should:

(i) specify all existing oil pipeline and vessel discharge facilities, including the present installed capacities, which could be used for the various scenarios;

(ii) indicate what capability exists for expanding the existing oil pipeline and vessel discharge capabilities including costs of such expansions;

(iii) provide alternative possibilities of developing new pipeline and vessel discharge facilities including their costs, that could be used to meet Canada's future incremental import oil requirements; and

(iv) provide any views on the impact on refiners now processing indigenous crude oil who, in future, will be processing foreign oil.

submittors are requested to include relevant documentation, assumptions, calculations, illustrations, estimated costs in constant 1977 dollars and probable construction schedules in support of the submission.

NATIONAL ENERGY BOARD
LIST OF POOLS AND POOL GROUPINGS
FOR CRUDE OIL PRODUCIBILITY FORECAST

LIGHT CRUDE OIL
NORTHWEST TERRITORIES

FIELD	POOL	UNIT
NORMAN WELLS		
Norman Wells	All	-

BRITISH COLUMBIA

FIELD	POOL	UNIT
BLUEBERRY-TAYLOR PIPELINES		
Aitken Creek	Gething	-
Blueberry	Debolt	-
Inga	Inga	-
Other	-	-
TRANS-PRAIRIE PIPELINES LTD. - BEATTON RIVER - TAYLOR		
Beatton River	Halfway	-
Beatton River West	Bluesky Gething	-
Crush	Halfway	-
Currant	Halfway	-
Milligan Creek	Halfway	-
Peejay	Halfway	-
Weasel	Halfway	-
Wildmint	Halfway	-
Other	-	-
TRANS-PRAIRIE PIPELINES LTD., - BOUNDARY LAKE - TAYLOR		
Boundary Lake Unit No. 1	Boundary Lake	-
Boundary Lake Unit No. 2	Boundary Lake	-
Other	-	-
TRUCKED OIL		
Trucked Oil	-	-

ALBERTA

FIELD	POOL	UNIT
BOW RIVER PIPE LINES LTD.		
Provost	Viking CAK	-
Other	-	-
CREMONA PIPELINE		
Crossfield	Cardium A	-
Harmattan East	Rundle	-
Harmattan Elkton	Rundle C	-
Other	-	-
FEDERATED PIPE LINES LTD.		
Carson Creek North	BHL A	-
Carson Creek North	BHL B	-
Judy Creek	BHL A	-
Judy Creek	BHL B	-
Swan Hills	BHL A & B	-
Swan Hills	BHL C	-
Swan Hills South	BHL A & B	-
Virginia Hills	BHL	-
Other	-	-
GIBSON PETROLEUM COMPANY LIMITED		
Bellshill Lake	Blairmore	-
Thompson Lake	Blairmore	-
GULF ALBERTA PIPE LINE		
Clive	D-2A	-
Clive	D-3A	-
Drumheller	D-2B	-
Duhamel	D-2A	-
Duhamel	D-3B	-
Erskine	D-3	-
Fenn Big Valley	D-2A	-
Hussar	Glauconitic A	-
Joffre	D-2	33%
Stettler	D-2A	-
Stettler	D-3A	-
West Drumheller	D-2A	-
Other	-	-
THE IMPERIAL PIPE LINE COMPANY LIMITED: ELLERSLIE		
Acheson	D-3A	-
Golden Spike	D-3A	-
Other	-	-
THE IMPERIAL PIPE LINE COMPANY LIMITED: EXCELSIOR		
Excelsior	D-2	-
Fairydell Bon Accord	D-3A	-
Other	-	-

FIELD	POOL	UNIT
THE IMPERIAL PIPE LINE COMPANY LIMITED: LEDUC		
Leduc Woodbend	D-2A	-
Leduc Woodbend	D-3A	-
Other	-	-
THE IMPERIAL PIPE LINE COMPANY LIMITED: REDWATER		
Redwater	D-3	-
MURPHY MILK RIVER PIPE LINE		
Coutts	Total	-
Manyberries	Total	-
Red Coulee	Total	-
NORCEN ENERGY RESOURCES LTD.		
Joarcam	Viking	-
PEACE RIVER OIL PIPE LINE CO. LTD.		
Goose River	BHL A	-
Kaybob	BHL A	-
Kaybob South	Triassic A	-
Nipisi	Gilwood A	33%
Simonette	D-3	-
Snipe Lake	BHL	-
Sturgeon Lake	D-3	-
Sturgeon Lake South	D-3	-
Utikuma	KR Sand A	-
Other	-	-
PEMBINA PIPE LINE LTD.		
Pembina	Cardium	-
Pembina	Keystone Belly River B	-
Willesden Green	Cardium A	70%
Other	-	-
RAINBOW PIPE LINE COMPANY LTD.		
Mitsue	Gilwood A	-
Nipisi	Gilwood A	67%
Rainbow	KR A	-
Rainbow	KR B	-
I.S. No. I	Other	-
Rainbow	KR F	-
Rainbow	KR AA	-
I.S. No. II	Other	-
I.S. No. 2	Total	-
Rainbow	Other	-
Rainbow South	KR A	-
Rainbow South	KR B	-
Rainbow South	KR E	-
Virgo	Total	-
Zama	Total	-
Other	-	-
RANGELAND PIPELINE COMPANY LIMITED		
Ferrier	Cardium D	-
Ferrier	Cardium E	-
Gilby	Jurassic C	-
Gilby	Mannville B	-
Gilby	Viking A	-
Innisfail	D-3	-
Joffre	D-2	67%
Medicine River	Glauconitic A	-
Medicine River	Jurassic A	-
Medicine River	Jurassic D	-
Sundre	Rundle A	-
Willesden Green	Cardium A	30%
Other	-	-
TEXACO EXPLORATION CANADA LTD.		
Bonnie Glen	D-3A	-
Glen Park	D-3A	-
Westerose	D-3	-
Wizard Lake	D-3A	-
Other	-	-
TRANSPRAIRIE PIPELINES LTD.: BOUNDARY LAKE SOUTH		
Boundary Lake South	Triassic E	-
Boundary Lake South	Triassic C	-
Boundary Lake South	Triassic H	-

NATIONAL ENERGY BOARD
LIST OF POOLS AND POOL GROUPINGS
FOR CRUDE OIL PRODUCIBILITY FORECAST

FIELD	POOL	UNIT
TWINING PIPELINE DIVISION		
Twining	Rundle A & Lower Mannville A	-
Twining	Rundle	-
Other	-	-
VALLEY PIPE LINE		
Turner Valley	Rundle & Shallow	-
TRUCK AND TANK CAR		
Truck and Tank Car	Total	-

SASKATCHEWAN

FIELD	POOL	UNIT
WESTSPUR MEDIUM PIPE LINE: BATCHED LIGHT		
Flat Lake	Ratcliffe	Vol. Unit No. 1
Freda Lake	Ratcliffe	-
Sherwood	Frobisher	-
Skinner	Ratcliffe	-
WESTSPUR PIPE LINE COMPANY: S.E. SASKATCHEWAN LIGHT		
Alida East	Total	-
Carnduff	Midale	East Unit
Elmore	Frobisher	Vol. Unit
Ingoldsby	Frobisher Alida	Vol. Unit
Kenosee	Tilston	Vol. Unit
Parkman	Tilston Souris Valley	-
Queensdale East	Frobisher Alida	Vol. Unit
Rosebank	Frobisher Alida	Vol. Unit No. 1
Steelman	Midale	Unit IA
Steelman	Midale	Unit II
Steelman	Midale	Unit III
Steelman	Midale	Unit IV
Steelman	Midale	Unit VI
Willmar	Frobisher Alida	Non-Unit
Workman	Frobisher	Vol. Unit No. 1
Other	-	-
TRANS-PRAIRIE PIPELINES LTD.		
Daly	Mississippian	-
Routledge	Mississippian	-
North Virden Scallion	Mississippian	-
Virden Roselea	Mississippian	-
Other	-	-

ONTARIO

ONTARIO		
Ontario	Total	-

HEAVY CRUDE OIL

ALBERTA

FIELD	POOL	UNIT
BOW RIVER PIPE LINES LTD.: HEAVY		
Bantry	Mannville	-
Countess	Upper Mannville D	-
Countess	Upper Mannville H	-
Grand Forks	Lower Mannville D	-
Hays	Lower Mannville A	-
Lathom	Upper Mannville A	-
Taber	Mannville D	-
Taber South	Mannville B	-
Other	-	-

FIELD	POOL	UNIT
B.P. EXPLORATION CANADA LIMITED		
Chauvin	Mannville A	-
Chauvin South	Sparky A & B	-
Chauvin South	Sparky E	-
Chauvin South	Sparky H	-
Chauvin South	Lloydminster D	-
Other	-	-
HUSKY PIPELINE LTD. & MANITO PIPELINES LTD.		
Lloydminster	Sparky C & GP A	-
Lloydminster	Sparky & GP C	-
Viking Kinsella	Wainwright B	-
Wainwright	Wainwright & Sparky A	-
Wildmere	Lloydminster A & Sparky B	-
Other	-	-
TRUCK AND TANK CAR		
Cessford	Total	-
Other	-	-

SASKATCHEWAN

FIELD	POOL	UNIT
HUSKY PIPELINE LTD. & MANITO PIPELINES LTD.		
Aberfeldy	Sparky	Aberfeldy Unit
South Aberfeldy	Sparky	Voluntary Unit
Dulwich	Sparky	-
Epping	Sparky & GP	Non-Unit
South Epping	Sparky & GP	Unit No. 1
S.W. Epping	Sparky	Vol. Unit No. 1
Furness	Sparky	-
Golden Lake North	Sparky & Waseca	Vol. Unit
Golden Lake North	Sparky & Waseca	Non-Unit
Golden Lake South	Sparky	-
Golden Lake South	Waseca	-
Gully Lake	Waseca	Vol. Unit No. 1
Gully Lake	Waseca	Non-Unit
Lashburn	Waseca	Vol. Unit
Lone Rock	Sparky	-
Tangleflags	Total	-
Other	-	-
BOW RIVER PIPE LINES LTD.		
Coleville	Bakken	-
Dodsland	Viking	Eagle Lake Vol. Unit
Dodsland	Viking	Gleneath Unit
Eureka	Viking	South Unit
North Hoosier	Bakken	Vol. Unit
North Hoosier	Basal Blairmore	Vol. Unit
Plato	Viking	-
Smiley Dewar	Viking	-
Other	-	-
SOUTH SASKATCHEWAN PIPE LINE COMPANY		
Battrum	Roseray	Unit No. 1
Cantaur Main	Cantaur	Unit
Dollard	Upper Shaunavon	Unit
Fosterton	Roseray	Main Unit
Gull Lake North	Upper Shaunavon	Unit
Instow	Upper Shaunavon	Unit
Main Success	Roseray	Unit
North Premier	Roseray	Unit No. 3
Rapdan	Upper Shaunavon	Unit
South Success	Roseray	Unit
Suffield	Upper Shaunavon	Unit No. 2
Verlo	Roseray	Unit
Other	-	-
WESTSPUR PIPE LINE COMPANY - S.E. SASKATCHEWAN MEDIUM		
Benson	Midale	Unit
Innes	Frobisher	-
Lost Horse Hill	Frobisher Alida	Vol. Unit No. 1
Midale	Central Midale	Unit
Midale	Central Midale	Non-Unit
Viewfield	Frobisher	Non-Unit
Weyburn	Midale	Unit
Weyburn	Midale	Non-Unit
Other	-	-

APPENDIX 2

A. NATIONAL ENERGY BOARD
CRUDE OIL PRODUCIBILITY FORECAST

FIELD:

POOL:

UNIT:

SUBMITTOR:

DATE:

B. PRODUCIBILITY FORECAST
From
Established Reserves at 1-1-78

YEAR	BARRELS PER DAY
1978	
1979	
1980	
1981	
1982	
1983	
1984	
1985	
1986	
1987	
1988	
1989	
1990	
1991	
1992	
1993	
1994	
1995	

C. OIL RESERVOIR DATA
For
Established Reserves at 1-1-78

Area, acres	
Average pay, ft	
Rock volumes, acre-ft	
Porosity, %	
Connate water, %	
Shrinkage, %	
Initial oil in place, MSTB	
Hor. permeability, md	
Vert. permeability, md	
Pressure-datum, ft. ss.	
Initial pressure, psia	
Initial oil viscosity, cp	
Current pressure, psia	
Current oil viscosity, cp	
Primary recovery, %	
Improved recovery, %	
Improved recovery mechanism	
Total recoverable oil, MSTB	
Cumulative oil production to 1-1-78, MSTB	

D. POTENTIAL RESERVES ADDITIONS

DRILLING POTENTIAL

No. of Wells ______________ Recoverable Oil, MSTB ______________
Comments ______________

IMPROVED RECOVERY POTENTIAL

Method ______________ Recoverable Oil, MSTB ______________
Comments ______________

Gas Plant	Location	Operator
Acheson	2-53-26W4	Canadian Propane Gas and Oil of Alberta Ltd.
Bonnie Glen	SW17-47-27W4	Texaco Exploration Canada Ltd.
Boundary Lake South	14-85-13W6	Imperial Oil Ltd.
Brazeau River	6-10-44-12W5	CDC Oil and Gas Limited
Brazeau River	12-46-14W5	Hudson's Bay Oil & Gas Co. Ltd.
Burnt Timber	7-13-30-7W5	Shell Canada Resources Limited
Caroline	12-36-34-6W5	Altana Exploration Company
Caroline	SW20-34-4W5	Hudson's Bay Oil & Gas Co. Ltd.
Carson Creek	4-23-61-17W5	Mobil Oil Canada, Ltd.
Carstairs-Crossfield	6-3-30-2W5	Home Oil Company Limited
Cessford	2-28-24-12W4	Hudson's Bay Oil & Gas Co. Ltd.
Cochrane	16-26-4W5	Alberta Natural Gas Company Ltd. (straddle plant)
Crossfield	10-2-26-29W4	Petrogas Processing Ltd.
Crossfield East	9-14-28-1W5	Amoco Canada Petroleum Co. Ltd.
Dunvegan	15-3-81-4W6	Anderson Exploration Ltd.
Edson	SW11-53-18W5	Hudson's Bay Oil & Gas Co. Ltd.
Ellerslie	4-51-24W4	Edmonton Liquid Gas Ltd. (straddle plant)
Empress	12-20-1W2	Dome Petroleum Ltd. (straddle plant)
Empress	11-20-1W2	Pacific Petroleums Ltd. (straddle plant)
Ferrier	2-6-41-7W5	Amerada Minerals Corp. of Canada Ltd.
Ferrier	1-20-39-7W5	Seafort Petroleum Ltd.
Fort Saskatchewan	14-55-22W4	Chevron Standard Ltd. (reprocessing facility)
Ghost Pine	8-11-31-21W4	Gulf Oil Canada Ltd.
Ghost Pine	4-33-31-23W4	Mobil Oil Canada Ltd.
Gilby	15-22-40-3W5	Texaco Exploration Canada Ltd.
Gold Creek	NW26-67-5W6	Atlantic Richfield Canada Ltd.
Golden Spike	22-51-27W4	Imperial Oil Ltd.
Greencourt	9-26-59-9W5	Petrofina Canada Ltd.
Harmattan	NE27-31-4W5	Canadian Superior Oil Ltd.
Homeglen-Rimbey	5-44-1W5	Gulf Oil Canada Ltd.
Hussar	13-36-24-21W4	CDC Oil and Gas Ltd.
Innisfail	1-3-35-1W5	Shell Canada Resources Ltd.
Judy Creek	15-25-64-11W5	Imperial Oil Ltd.
Jumping Pound	13-13-25-5W5	Shell Canada Resources Ltd.
Kaybob	8-9-64-19W5	Pacific Petroleums Ltd.
Kaybob South	15-59-18W5	Chevron Standard Ltd.
Kaybob South	1&12-62-20W5	Hudson's Bay Oil & Gas Co. Ltd.
Leduc-Woodbend	2-34-50-26W4	Imperial Oil Ltd.
Lone Pine Creek	6-27-29-28W4	Canadian Superior Oil Ltd.
Lone Pine Creek	6-23-30-28W4	Hudson's Bay Oil & Gas Co. Ltd.
Minnehik-Buck Lake	10-5-46-6W5	CanDel Oil Ltd.
Mitsue	30-72-4W5	Chevron Standard Ltd.
Nevis	15-22-39-22W4	Chevron Standard Ltd.
Nevis	9-33-38-22W4	Gulf Oil Canada Ltd.
Nipisi	30-72-4W5	Amoco Canada Petroleum Co. Ltd.
Olds	6-18-23-1W5	Amerada Minerals Corp. of Canada Ltd.
Paddle River	13-6-57-8W5	Canada-Cities Service, Ltd.
Pembina	13-24-48-7W5	Amoco Canada Petroleum Co. Ltd. (formerly Goliad plant)
Pembina	13-22-49-10W5	Texaco Exploration Canada Ltd.
Pincher Creek	23-4-29W4	Gulf Oil Canada Ltd.
Quirk Creek	4-21-4W5	Imperial Oil Ltd.
Rainbow	10-10-109-8W6	Aquitaine Company of Canada Ltd.
Rainbow	12-23-110-7W6	Imperial Oil Ltd.
Rainbow	10-110-6W6	Mobil Oil Canada, Ltd.
Redwater	29-57-21W4	Imperial Oil Ltd.
Ricinus	11-30-36-8W5	Amoco Canada Petroleum Co. Ltd.
Rosevear	33-54-15W5	Sun Oil Company Ltd.
Simonette	6-63-25W5	Shell Canada Resources Ltd.
Strachan (Ram River)	6-2-37-10W5	Aquitaine Company of Canada Ltd.
Strachan	11-35-37-9W5	Gulf Oil Canada Ltd.
Sturgeon Lake South	2-69-22W5	Hudson's Bay Oil & Gas Co. Ltd.
Swan Hills	1-8-70-10W5	Shell Canada Resources Ltd.
Sylvan Lake	1-21-38-2W5	Chevron Standard Ltd.
Sylvan Lake	14-32-37-3W5	Hudson's Bay Oil & Gas Co. Ltd.
Turner Valley	14-6-20-2W5	Western Decalta Petroleum Ltd.
Waterton	20-4-30W4	Shell Canada Resources Ltd.
Whitecourt	12-26-59-11W5	Pacific Petroleums Ltd.
Wildcat Hills	6-16-26-5W5	Petrofina Canada Ltd.
Wilson Creek	1-29-43-4W5	Amerada Minerals Corp. of Canada Ltd.
Wimborne	4-12-34-26W4	Mobil Oil Canada, Ltd.
Windfall	8-17-60-15W5	Amoco Canada Petroleum Co. Ltd.
Worsley	7-22-87-7W6	Shell Canada Resources Ltd.
Steelman	21-4-5W2	Steelman Gas Ltd. (Dome Petroleum)
Taylor		Westcoast Petroleum Ltd.

NATIONAL ENERGY BOARD

LIST OF PLANTS

FOR PENTANES PLUS

PRODUCTION FORECAST

APPENDIX 4

NATIONAL ENERGY BOARD
PENTANES PLUS PRODUCTION FORECAST

PLANT: ______________
SUBMITTOR: ______________
DATE: ______________

PRODUCTION FORECAST
FROM ESTABLISHED RESERVES
AT 1-1-78

YEAR	BARRELS PER DAY
1978	________
1979	________
1980	________
1981	________
1982	________
1983	________
1984	________
1985	________
1986	________
1987	________
1988	________
1989	________
1990	________
1991	________
1992	________
1993	________
1994	________
1995	________

1977
AVERAGE GAS COMPOSITION
(MOL PERCENT)

COMPONENT	PLANT INLET GAS	PLANT SALES GAS
Methane	________	________
Ethane	________	________
Propane	________	________
Butanes	________	________
Pentanes+	________	________
Nitrogen	________	________
Hydrogen Sulphide	________	________
Other	________	________

If the pentanes plus is produced as part of an NGL mix stream, what percentage of the mix is constituted by pentanes plus?

____

If liquids are produced into a pipeline system, identify the system.

____

GAS RESERVES OF POOLS DEDICATED TO PLANT

POOL	GAS PURCHASER*	CURRENT PRODUCTION RATE (MMCFD)	INITIAL RESERVES (BCF @ 14.73 PSIA)	CUMULATIVE PRODUCTION AT 1-1-78 (BCF @ 14.73 PSIA)
________	________	________	________	________
________	________	________	________	________
________	________	________	________	________
________	________	________	________	________
________	________	________	________	________
________	________	________	________	________
________	________	________	________	________
________	________	________	________	________
________	________	________	________	________

* If there is more than one gas purchaser for any one pool, indicate all purchasers and percentage of pool total contracted by each.

APPENDIX 5

RECONCILIATION OF TOTAL MARKET PRODUCT SALES & FEEDSTOCK REQUIREMENTS

Thousands of Barrels Per Day

	1975		
	East of the Ottawa Valley Line	West of the Ottawa Valley Line	Total Canada
Total market product sales	733	862	1595
Deduct Product imports	(28)	(12)	(40)
Add Product exports	55	32	87
Net exports/(imports)	27	20	47
Net product transfers out/(in)	30	(30)	-
Industry use and loss & other adjustments	33	34	67
Total feedstock requirements	823	886	1709
Deduct gas plant butanes supplied to refineries	-	(13)	(13)
Deduct foreign feedstock refined	(816)	(1)	(817)
Canadian feedstock refined	7	872	879
Canadian feedstock by type:			
Heavy Crude Oil	-	73	73
Segregated Pentanes Plus	-	31	31
Synthetic Crude	-	30	30
Other Light and Medium	7	738	745

ESTABLISHED RESERVES OF CONVENTIONAL CRUDE OIL

NEB Estimates

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
NORTHWEST TERRITORIES			
1. Norman Wells			
Norman Wells	60.0	22.1	37.9
Total	**60.0**	**22.1**	**37.9**
BRITISH COLUMBIA			
1. Blueberry - Taylor Pipelines			
Aitken Creek - Gething	6.4	5.0	1.4
Blueberry - Debolt	13.5	10.9	2.6
Eagle Belloy (85%)	13.2	0.8	12.4
Inga - Inga	36.0	24.9	11.1
Other	2.2	1.3	0.9
Total	**71.3**	**42.9**	**28.4**
2. Trans-Prairie Pipelines Ltd.: Beatton River - Taylor			
Beatton River - Halfway	9.5	6.8	2.7
Beatton River West - Bluesky Gething	4.6	3.0	1.6
Eagle Belloy (15%)	2.3	0.1	2.2
Milligan Creek - Halfway	40.1	37.3	2.8
Peejay - Halfway	56.6	50.6	6.0
Weasel - Halfway	17.5	12.4	5.1
Wildmint - Halfway	7.9	7.1	0.8
Other	9.4	7.5	1.9
Total	**147.9**	**124.8**	**23.1**
3. Trans-Prairie Pipelines Ltd.: Boundary Lake - Taylor			
Boundary Lake Unit No. 1	117.0	59.3	57.7
Boundary Lake Unit No. 2	74.0	46.4	27.6
Other	21.1	15.3	5.8
Total	**212.1**	**121.0**	**91.1**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
4. Trucked Oil (B.C. Total)			
Trucked Oil	5.8	2.6	3.2
Total	**5.8**	**2.6**	**3.2**
BRITISH COLUMBIA TOTAL	**437.1**	**291.3**	**145.8**

ALBERTA

1. Bow River Pipe Lines Ltd.: Light & Medium			
Provost - Viking CAK	57.6	27.6	30.0
Other	10.6	1.7	8.9
Total	**68.2**	**29.3**	**38.9**
2. Bow River Pipe Lines Ltd.: Heavy			
Bantry - Mannville A	40.6	23.9	16.7
Countess - Upper Mannville B	6.9	3.7	3.2
Countess - Upper Mannville D	27.6	14.0	13.6
Countess - Upper Mannville H	15.8	6.8	9.0
Countess - Upper Mannville O	7.5	1.1	6.4
Grand Forks - Upper Mannville B	6.8	1.4	5.4
Grand Forks - Lower Mannville D	34.2	7.0	27.2
Grand Forks - Lower Mannville K	7.7	1.9	5.8
Hays - Lower Mannville A	9.4	5.7	3.7
Lathom - Upper Mannville A	11.3	5.3	6.0
Taber - Mannville D	13.4	6.8	6.6
Taber South - Mannville B	11.1	9.2	1.9
Other	84.0	37.8	46.2
Total	**276.3**	**124.6**	**151.7**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
3. BP Exploration Canada Limited			
Chauvin - Mannville A	7.7	5.3	2.4
Chauvin South - Sparky A&B	11.3	4.1	7.2
Chauvin South - Sparky E	2.5	1.1	1.4
Chauvin South - Sparky H	3.9	0.7	3.2
Chauvin South - Lloydminster D	1.7	1.0	0.7
Other	6.8	2.5	4.3
Total	**33.9**	**14.7**	**19.2**
4. Cremona Pipeline			
Crossfield - Cardium A	17.9	16.0	1.9
Harmattan East - Rundle	80.8	47.4	33.4
Harmattan Elkton - Rundle C	58.2	40.3	17.9
Other	33.0	23.5	9.5
Total	**189.9**	**127.2**	**62.7**
5. Federated Pipe Lines Ltd.			
Carson Creek North - BHL A	40.2	16.7	23.5
Carson Creek North - BHL B	124.1	58.4	65.7
Judy Creek - BHL A	390.0	203.4	186.6
Judy Creek - BHL B	125.0	66.2	58.8
Swan Hills - BHL A&B	778.0	379.7	398.3
Swan Hills - BHL C	190.0	80.5	109.5
Swan Hills South - BHL A&B	452.8	211.2	241.6
Virginia Hills - BHL	155.0	94.3	60.7
Other	30.3	11.7	18.6
Total	**2285.4**	**1122.1**	**1163.3**
6. Gibson Petroleum Company Limited			
Bellshill Lake - Blairmore	49.9	28.5	21.4
Thompson Lake - Blairmore	4.1	2.6	1.5
Total	**54.0**	**31.1**	**22.9**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
7. Gulf Alberta Pipe Line			
Clive - D-2A	21.6	7.5	14.1
Clive - D-3A	43.4	17.6	25.8
Drumheller - D-2B	10.3	4.3	6.0
Duhamel - D-2A	5.8	5.2	0.6
Duhamel - D-3B	7.5	5.8	1.7
Erskine - D-3	24.2	19.3	4.9
Fenn Big Valley - D-2A	239.0	165.2	73.8
Hussar - Glauconitic A	20.6	12.4	8.2
Joffre - D-2	70.6	34.1	36.5
Stettler - D-2A	25.0	21.9	3.1
Stettler - D-3A	23.2	14.4	8.8
West Drumheller - D-2A	29.8	22.4	7.4
Other	162.2	115.5	46.7
Total	**683.2**	**445.6**	**237.6**
8. Husky Pipeline Ltd. & Manito Pipelines Ltd.			
Lloydminster - Sparky C and GP A	8.8	5.1	3.7
Lloydminster - Sparky and GP C	22.9	12.1	10.8
Viking Kinsella - Wainwright B	27.5	3.9	23.6
Wainwright - Wainwright & Sparky A	62.7	36.5	26.2
Wildmere - Lloydminster A & Sparky B	15.4	2.8	12.6
Other	24.1	10.1	14.0
Total	**161.4**	**70.5**	**90.9**
9. The Imperial Pipe Line Company, Limited: Ellerslie			
Acheson - D-3A	107.9	71.7	36.2
Golden Spike - D-3A	210.0	154.7	55.3
Other	60.3	37.2	23.1
Total	**378.2**	**263.6**	**114.6**
10. The Imperial Pipe Line Company. Limited: Excelsior			
Excelsior - D-2	24.5	20.0	4.5
Fairydell Bon Accord - D-3A	11.5	8.4	3.1
Other	4.7	3.7	1.0
Total	**40.7**	**32.1**	**8.6**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
11. The Imperial Pipe Line Company, Limited: Leduc			
Leduc Woodbend - D-2A	89.0	85.8	3.2
Leduc Woodbend - D-3A	243.5	222.9	20.6
Other	42.0	37.7	4.3
Total	**374.5**	**346.4**	**28.1**
12. The Imperial Pipe Line Company, Limited: Redwater			
Redwater - D-3	797.0	624.2	172.8
Total	**797.0**	**624.2**	**172.8**
13. Murphy Milk River Pipe Line			
Coutts - Total	4.5	1.5	3.0
Manyberries - Total	4.7	1.6	3.1
Other	10.8	7.9	2.9
Total	**20.0**	**11.0**	**9.0**
14. Norcen Energy Resources Ltd.			
Joarcam - Viking	94.4	82.0	12.4
Total	**94.4**	**82.0**	**12.4**
15. Peace River Oil Pipe Line Co. Ltd.			
Goose River - BHL	49.2	20.7	28.5
Kaybob - BHL A	114.0	66.6	47.4
Kaybob South - Triassic A	87.5	36.8	50.7
Nipisi - Gilwood A(39%)	117.0	51.8	65.2
Simonette - D-3	57.8	26.8	31.0
Snipe Lake - BHL	78.0	37.3	40.7
Sturgeon Lake - D-3	22.8	15.7	7.1
Sturgeon Lake South - D-3	157.0	82.4	74.6
Utikuma - KR SAND A (16%)	5.6	1.8	3.8
Other	143.1	55.2	87.9
Total	**832.0**	**395.1**	**436.9**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
16. Pembina Pipe Line Ltd.			
Pembina - Cardium	1367.3	851.9	515.4
Pembina - Keystone Belly River B	60.1	22.7	37.4
Willesden Green - Cardium A(70%)	146.8	48.0	98.8
Other	134.2	43.4	90.8
Total	**1708.4**	**966.0**	**742.4**
17. Rainbow Pipe Line Company, Ltd.			
Mitsue - Gilwood A	341.0	149.7	191.3
Nipisi - Gilwood A(61%)	183.0	81.1	101.9
Rainbow - KR A	71.1	31.9	39.2
Rainbow - KR B	171.6	76.7	94.9
I.S. No. 1 Other	81.0	33.4	47.6
Rainbow - KR F	112.0	50.0	62.0
Rainbow - KR AA	78.3	27.1	51.2
I.S. No. 11 Other	18.1	12.7	5.4
I.S. No. 2 Total	28.0	10.7	17.3
Rainbow Other	76.6	32.0	44.6
Rainbow South - KR A	19.4	8.3	11.1
Rainbow South - KR B	32.8	11.4	21.4
Rainbow South - KR E	25.2	9.3	15.9
Utikuma Keg River A(84%)	29.4	9.6	19.8
Virgo - Total	35.9	27.0	8.9
Zama - Total	72.5	49.7	22.8
Other	74.1	25.3	48.8
Total	**1450.0**	**645.9**	**804.1**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
18. Rangeland Pipeline Company Limited			
Ferrier - Cardium D	12.1	5.2	6.9
Ferrier - Cardium E	30.5	6.4	24.1
Gilby - Jurassic B	23.1	9.7	13.4
Gilby - Mannville B	15.1	4.1	11.0
Gilby - Viking A	16.2	14.3	1.9
Innisfail - D-3	74.4	48.9	25.5
Medicine River - Glauconitic A	13.7	4.8	8.9
Medicine River - Jurassic A	11.3	7.0	4.3
Medicine River - Jurassic D	13.4	5.7	7.7
Sundre - Rundle A	32.0	22.7	9.3
Willesden Green - Cardium A(30%)	63.0	20.6	42.4
Other	178.8	72.1	106.7
Total	**483.6**	**221.5**	**262.1**
19. Texaco Exploration Canada Ltd.			
Bonnie Glen - D-3A	460.3	282.9	177.4
Glen Park - D-3A	21.1	12.9	8.2
Westerose - D-3	133.4	67.5	65.9
Wizard Lake - D-3A	323.0	187.5	135.5
Other	10.3	9.3	1.0
Total	**948.1**	**560.1**	**388.0**
20. Trans-Prairie Pipelines Ltd.: Boundary Lake South			
Boundary Lake South - Triassic C	4.1	1.1	3.0
Boundary Lake South - Triassic E	.23.8	7.1	16.7
Other	1.6	0.1	1.5
Total	**29.5**	**8.3**	**21.2**
21. Twining Pipeline Division			
Twining - Rundle A and LM A	22.4	7.8	14.6
Twining North - Rundle	7.7	2.2	5.5
Other	3.6	0.8	2.8
Total	**33.7**	**10.8**	**22.9**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
22. Valley Pipe Line			
Turner Valley - Rundle & Shallow	141.5	128.0	13.5
Total	**141.5**	**128.0**	**13.5**
23. Truck and Tank Car (Light)			
Total	**4.8**	**3.6**	**1.2**
24. Truck and Tank Car (Heavy)			
Cessford - Total	28.7	17.0	11.7
Other	24.2	11.9	12.3
Total	**52.9**	**28.9**	**24.0**
25. Undefined and Confidential			
Light	41.5	8.1	33.4
Heavy	7.7	1.9	5.8
Total	**49.2**	**10.0**	**39.2**
ALBERTA TOTAL	**11190.8**	**6302.6**	**4888.2**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
SASKATCHEWAN			
1. Husky Pipeline Ltd. & Manito Pipelines Ltd.			
Aberfeldy - Sparky, Aberfeldy Unit	33.0	22.7	10.3
South Aberfeldy - Sparky, Voluntary Unit	10.9	6.9	4.0
Dulwich - Sparky	12.1	8.9	3.2
Epping - Sparky and G.P., Non-Unit	13.1	8.9	4.2
South Epping - Sparky and G.P., Unit No. 1	18.3	11.8	6.5
S.W. Epping Sparky Vol. Unit No. 1	6.5	3.3	3.2
Furness - Sparky	2.3	1.5	0.8
Golden Lake North - Waseca & Sparky, Vol. Unit	11.2	6.3	4.9
Golden Lake North - Waseca & Sparky, Non-Unit	2.7	1.3	1.4
Golden Lake South - Sparky	3.5	1.4	2.1
Golden Lake South - Waseca	9.5	4.1	5.4
Gully Lake - Waseca, Vol. Unit No. 1	5.6	2.3	3.3
Gully Lake - Waseca, Non-Unit	3.5	1.3	2.2
Lashburn - Waseca, Vol. Unit	5.3	4.0	1.3
Lone Rock - Sparky	7.7	6.9	0.8
Tangleflags (Total)	15.5	4.1	11.4
Other	45.0	24.3	20.7
Total	**205.7**	**120.0**	**85.7**
2. Bow River Pipe Lines Ltd. (Heavy Blend)			
Coleville - Bakken	46.3	31.0	15.3
Dodsland - Viking, Eagle Lake, Vol. Unit	14.8	8.7	6.1
Dodsland - Viking, Gleneath Unit	14.3	8.0	6.3
Eureka - Viking, South Unit	9.5	5.3	4.2
North Hoosier - Bakken, Vol. Unit	6.5	3.3	3.2
North Hoosier - Basal Blairmore, Vol. Unit	3.8	2.4	1.4
Smiley Dewar - Viking	32.7	21.8	10.9
Other	27.5	18.3	9.2
Total	**155.4**	**98.8**	**56.6**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
3. South Saskatchewan Pipe Line Company			
Battrum - Roseray, Unit No. 1	36.1	23.0	13.1
Cantuar Main - Cantuar, Unit	25.0	18.5	6.5
Dollard - Upper Shaunavon, Unit	85.6	70.4	15.2
Fosterton - Roseray, Main Unit	64.2	49.2	15.0
Gull Lake North - Upper Shaunavon, Unit	19.6	16.6	3.0
Instow - Upper Shaunavon, Unit	51.0	39.0	12.0
Main Success - Roseray, Unit	17.1	15.1	2.0
North Premier - Roseray, Unit No. 3	13.2	11.4	1.8
Rapdan - Upper Shaunavon, Unit	19.3	11.7	7.6
South Success - Roseray, Unit	23.3	18.5	4.8
Suffield - Upper Shaunavon, Unit No. 2	5.0	2.7	2.3
Verlo - Roseray, Unit	12.0	4.9	7.1
Other	180.9	117.6	63.3
Total	**552.3**	**398.6**	**153.7**
4. Westspur Pipe Line Company - S.E. Saskatchewan Medium			
Benson - Midale, Unit	10.5	7.0	3.5
Innes - Frobisher	13.3	8.7	4.6
Lost Horse Hill - Frobisher Alida, Vol. Unit No. 1	12.5	9.7	2.8
Midale - Central Midale, Unit	109.4	79.2	30.2
Midale - Central Midale, Non-Unit	8.0	4.5	3.5
Viewfield - Frobisher	9.0	3.2	5.8
Weyburn - Midale, Unit	332.1	222.1	110.0
Weyburn - Midale, Non-Unit	6.7	4.3	2.4
Other	93.1	60.3	32.8
Total	**594.6**	**399.0**	**195.6**
5. Westspur - Medium Pipe Line - Batched Light			
Flat Lake - Ratcliffe, Vol. Unit No. 1	11.8	6.3	5.5
Freda Lake - Ratcliffe	3.0	1.6	1.4
Sherwood - Frobisher	11.4	8.6	2.8
Skinner Lake - Ratcliffe	2.0	0.8	1.2
Total	**28.2**	**17.3**	**10.9**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
6. Westspur Pipe Line Company - S.E. Saskatchewan Light			
Alida East - Alida, Unit	12.2	10.2	2.0
Carnduff - Midale, East Unit	17.0	15.0	2.0
Elmore - Frobisher Vol. Unit	14.0	8.3	5.7
Ingoldsby - Frobisher Alida, Vol. Unit	17.0	11.8	5.2
Kenosee - Tilston, Vol. Unit	12.5	7.9	4.6
Parkman - Tilston Souris Valley	18.8	15.1	3.7
Queensdale East-Frobisher Alida, Non-Unit	29.2	19.9	9.3
Rosebank - Frobisher Alida, Vol. Unit No. 1	22.5	19.9	2.6
Steelman - Midale, Unit 1A	60.5	45.1	15.4
Steelman - Midale, Unit II	52.9	43.1	9.8
Steelman - Midale, Unit III	26.7	21.5	5.2
Steelman - Midale, Unit IV	33.5	24.0	9.5
Steelman - Midale, Unit VI	58.2	50.1	8.1
Willmar - Frobisher Alida, Non-Unit	19.0	13.6	5.4
Workamn - Forbisher, Vol. Unit No. 1	10.9	8.7	2.2
Other	272.1	206.0	66.1
Total	**677.0**	**520.2**	**156.8**
SASKATCHEWAN TOTAL	**2213.2**	**1553.9**	**659.3**

MANITOBA

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
1. Trans-Prairie Pipelines Ltd.			
Daly - Mississippian	22.2	18.1	4.1
North Virden Scallion - Mississippian	70.4	49.2	21.2
Routledge - Mississippian	14.8	12.6	2.2
Virden Roselea - Mississippian	47.0	31.2	15.8
Other	9.2	7.2	2.0
Total	**163.6**	**118.3**	**45.3**
MANITOBA TOTAL	**163.6**	**118.3**	**45.3**

	Initial Recoverable Reserves MMstb	Cumulative Production to 1/1/78 MMstb	Remaining Reserves at 1/1/78 MMstb
ONTARIO			
1. Ontario			
ONTARIO TOTAL	**60.9**	**54.7**	**6.2**
CANADA - TOTAL*	**14125.6**	**8342.9**	**5782.7**

*Frontier reserves not included.

POTENTIAL PRODUCIBILITY FROM ESTABLISHED CRUDE OIL RESERVES
NEB Forecast
b/d

LIGHT CRUDE OIL

NORTHWEST TERRITORIES

Norman Wells

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Pipeline Total	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**

BRITISH COLUMBIA

Blueberry - Taylor Pipelines

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Aitken Creek - Gething	747	619	513	425	352	292	242	200	166	138	114	21	0	0	0	0	0	0
Blueberry - Debolt	788	681	594	523	464	415	373	337	306	279	255	235	216	200	186	173	161	151
Eagle Belloy (85%)	2018	2656	2975	2964	2721	2413	2140	1898	1683	1493	1324	1174	1042	924	819	726	644	571
Inga - Inga	3938	3458	3037	2667	2342	2057	1806	1586	1393	1223	1074	943	828	727	639	561	492	432
Other	298	279	247	218	193	170	150	133	117	104	92	81	72	63	56	49	44	38
Pipeline Total	**7791**	**7695**	**7368**	**6799**	**6074**	**5349**	**4714**	**4156**	**3668**	**3238**	**2861**	**2456**	**2159**	**1916**	**1701**	**1511**	**1343**	**1194**

Trans-Prairie Pipelines Ltd.: Beatton River - Taylor

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Beatton River - Halfway	873	800	714	636	567	506	451	402	359	320	285	254	227	202	180	160	143	128
Beatton River West - Bluesky Gething	818	740	631	506	406	325	261	209	167	134	107	74	0	0	0	0	0	0
Eagle Belloy (15%)	356	468	525	523	483	429	380	337	299	265	235	208	185	164	145	129	114	101
Milligan Creek - Halfway	1384	1176	999	848	721	612	520	442	375	319	270	0	0	0	0	0	0	0
Peejay - Halfway	3586	3042	2385	1869	1466	1149	901	706	553	434	340	3	0	0	0	0	0	0
Weasel - Halfway	2295	2097	1827	1513	1253	1038	860	712	590	488	404	335	277	230	48	0	0	0
Wildmint - Halfway	491	391	311	248	197	157	125	99	79	63	27	0	0	0	0	0	0	0
Other	1010	849	714	601	505	425	357	301	253	185	0	0	0	0	0	0	0	0
Pipeline Total	**10815**	**9567**	**8108**	**6748**	**5602**	**4644**	**3858**	**3211**	**2678**	**2211**	**1671**	**876**	**690**	**596**	**374**	**290**	**258**	**229**

Trans-Prairie Pipelines Ltd.: Boundary Lake - Taylor

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Boundary Lake Unit No. 1	9851	9560	9124	8563	8036	7541	7077	6642	6233	5849	5489	5151	4834	4537	4258	3996	3750	3519
Boundary Lake Unit No. 2	6707	6155	5648	5182	4755	4364	4004	3674	3372	3094	2839	2605	2391	2194	2013	1847	1695	1555
Other	1853	1762	1607	1403	1224	1068	933	814	710	620	541	472	412	360	314	274	239	209
Pipeline Total	**18412**	**17478**	**16380**	**15149**	**14016**	**12974**	**12015**	**11131**	**10316**	**9564**	**8870**	**8230**	**7638**	**7091**	**6585**	**6117**	**5684**	**5284**

LIGHT CRUDE OIL

Trucked Oil (B.C. TOTAL)

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Trucked Oil	825	763	694	632	575	523	476	433	394	358	326	296	270	245	223	203	185	168
British Columbia Total	**37844**	**35504**	**32552**	**29330**	**26269**	**23492**	**21063**	**18933**	**17057**	**15373**	**13730**	**11859**	**10758**	**9850**	**8885**	**8122**	**7471**	**6876**

ALBERTA

Bow River Pipe Lines Ltd.: Light & Medium

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Provost - Viking CAK	7932	7156	6463	5844	5289	4791	4345	3943	3582	3258	2965	2701	2462	2247	2052	1875	1716	1570
Other	746	738	731	724	709	687	666	645	626	606	588	569	552	535	518	502	487	472
Pipeline Total	**8678**	**7895**	**7195**	**6568**	**5998**	**5479**	**5011**	**4589**	**4209**	**3864**	**3553**	**3271**	**3015**	**2782**	**2571**	**2378**	**2203**	**2043**

Cremona Pipeline

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Crossfield - Cardium A	797	700	615	540	474	416	366	321	282	248	217	191	33	0	0	0	0	0
Harmattan East - Rundle	11052	10202	9058	7749	6661	5751	4986	4340	3792	3325	2925	2582	2285	2029	1807	1613	1443	1295
Harmattan Elkton - Rundle C	6256	5496	4826	4238	3721	3268	2869	2519	2212	1942	1706	1498	1315	1155	1014	890	782	686
Other	3305	2945	2625	2339	2084	1857	1655	1475	1314	1171	1043	930	829	738	658	586	464	0
Pipeline Total	**21411**	**19345**	**17125**	**14867**	**12942**	**11293**	**9877**	**8657**	**7602**	**6687**	**5893**	**5201**	**4463**	**3923**	**3479**	**3090**	**2690**	**1981**

Federated Pipe Lines Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Carson Creek North - BHL A	5657	5381	5119	4754	4309	3905	3539	3208	2907	2635	2388	2165	1962	1778	1611	1460	1324	1200
Carson Creek North - BHL B	18717	18164	16848	14920	13213	11701	10362	9176	8126	7196	6372	5643	4997	4425	3919	3470	3073	2721
Judy Creek - BHL A	72186	62190	53578	46159	39767	34260	29516	25429	21907	18874	16260	14008	12068	10397	8957	7717	6648	5728
Judy Creek - BHL B	22351	19353	16758	14510	12564	10879	9419	8156	7062	6115	5295	4584	3969	3437	2976	2577	2231	1932
Swan Hills - BHL A&B	77938	73399	68671	63815	59303	55110	51214	47593	44228	41101	38195	35494	32985	30653	28485	26471	24600	22860
Swan Hills - BHL C	14631	13917	13091	12194	11386	10656	9994	9392	8843	8340	7879	7455	7065	6705	6371	6062	5774	5507
Swan Hills South - BHL A&B	64849	63565	59498	53126	47436	42356	37820	33770	30153	26924	24041	21466	19167	17114	15281	13645	12183	10879
Virginia Hills - BHL	13521	12607	11678	10745	9886	9096	8370	7701	7086	6520	5999	5519	5078	4673	4299	3956	3640	3349
Other	5763	5592	5427	4966	4278	3686	3175	2735	2356	2030	1748	1506	1297	1117	963	829	714	615
Pipeline Total	**295617**	**274173**	**250671**	**225193**	**202147**	**181653**	**163413**	**147163**	**132672**	**119737**	**108181**	**97845**	**88593**	**80303**	**72867**	**66191**	**60191**	**54794**

LIGHT CRUDE OIL

Gibson Petroleum Company Limited

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Bellshill Lake - Blairmore	6268	5648	5090	4587	4134	3725	3357	3025	2726	2457	2214	1995	1798	1620	1460	1316	1186	1069
Thompson Lake - Blairmore	421	404	377	340	307	277	250	225	203	183	165	149	135	121	110	99	89	80
Pipeline Total	**6689**	**6053**	**5467**	**4928**	**4441**	**4003**	**3607**	**3251**	**2930**	**2641**	**2380**	**2145**	**1933**	**1742**	**1570**	**1415**	**1275**	**1149**

Gulf Alberta Pipe Line

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Clive - D-2A	2671	2435	2227	2043	1880	1734	1604	1487	1382	1287	1200	1122	1050	985	926	871	821	774
Clive - D-3A	5900	5900	5900	5898	5513	4889	4336	3846	3411	3025	2683	2380	2110	1872	1660	1472	1306	1158
Drumheller - D-2B	1599	1507	1363	1234	1116	1010	914	827	748	677	612	554	501	453	410	371	336	304
Duhamel - D-2A	443	346	270	211	165	129	77	0	0	0	0	0	0	0	0	0	0	0
Duhamel - D-3B	719	619	532	458	394	339	292	251	216	186	160	137	118	101	87	42	0	0
Erskine - D-3	1193	1092	1006	931	866	808	757	711	671	634	600	570	542	517	494	472	453	434
Fenn Big Valley - D-2A	37810	33725	26990	21599	17286	13833	11070	8859	7090	5674	4541	3634	2908	2327	1862	1490	1192	291
Hussar - Glauconitic A	2487	2365	2174	1928	1710	1517	1345	1193	1058	939	832	738	655	581	515	457	405	359
Joffre - D-2	3900	4100	4200	4200	4200	4104	3781	3490	3237	3015	2819	2644	2489	2349	2222	2108	2003	1908
Stettler - D-2A	1268	1206	1082	914	772	652	550	465	392	331	280	236	200	139	0	0	0	0
Stettler - D-3A	2109	1938	1781	1636	1503	1381	1269	1166	1072	985	905	831	764	702	645	592	544	500
West Drumheller - D-2A	2721	2394	2105	1852	1629	1433	1260	1109	975	858	754	664	584	513	451	397	349	216
Other	11329	10994	10329	9389	8534	7757	7051	6409	5826	5295	4813	4375	3977	3615	3286	2987	2715	2468
Pipeline Total	**74153**	**68625**	**59964**	**52298**	**45572**	**39593**	**34313**	**29819**	**26082**	**22909**	**20205**	**17891**	**15903**	**14160**	**12564**	**11264**	**10128**	**8417**

The Imperial Pipe Line Company, Limited: Ellerslie

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Acheson - D-3A	16000	16000	15071	11879	9252	7205	5611	4370	3403	2650	2064	1607	1252	975	759	591	460	21
Golden Spike - D-3A	28883	23445	19031	15449	12540	10179	8263	6707	5444	4419	3587	2912	2364	1919	1557	1264	1026	833
Other	6794	6398	6025	5506	4876	4319	3826	3389	3001	2658	2355	2085	1847	1636	1449	1283	1137	1007
Pipeline Total	**51677**	**45844**	**40129**	**32835**	**26669**	**21705**	**17701**	**14467**	**11850**	**9729**	**8007**	**6606**	**5463**	**4530**	**3766**	**3139**	**2624**	**1862**

The Imperial Pipe Line Company, Limited: Excelsior

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Excelsior - D-2	2785	2279	1766	1369	1061	822	637	493	382	296	229	178	25	0	0	0	0	0
Fairydell Bon Accord - D-3A	1212	1052	913	793	688	598	519	450	391	339	295	256	222	193	167	145	126	109
Other	358	317	281	249	221	196	173	154	136	121	107	95	84	74	66	58	44	0
Pipeline Total	**4356**	**3649**	**2961**	**2412**	**1971**	**1616**	**1330**	**1098**	**910**	**757**	**632**	**529**	**332**	**267**	**234**	**204**	**170**	**109**

LIGHT CRUDE OIL

The Imperial Pipe Line Company, Limited: Leduc

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Leduc Woodbend - D-2A	987	1062	1100	1081	930	776	648	542	452	378	315	263	220	6	0	0	0	0
Leduc Woodbend - D-3A	10847	8831	7191	5855	4767	3881	3160	2573	2095	1705	1388	1130	920	749	610	497	232	0
Other	1325	1187	1063	951	852	763	683	612	548	490	439	393	352	315	282	253	226	203
Pipeline Total	**13160**	**11081**	**9354**	**7888**	**6549**	**5421**	**4493**	**3727**	**3096**	**2575**	**2144**	**1788**	**1493**	**1071**	**893**	**750**	**458**	**203**

The Imperial Pipe Line Company, Limited: Redwater

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Redwater - D-3	100679	79552	62859	49669	39246	31011	24503	19362	15299	12088	9552	7547	5963	4712	3723	2942	2324	1837
Pipeline Total	**100679**	**79552**	**62859**	**49669**	**39246**	**31011**	**24503**	**19362**	**15299**	**12088**	**9552**	**7547**	**5963**	**4712**	**3723**	**2942**	**2324**	**1837**

Murphy Milk River Pipe Line

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Coutts - Total	1020	1020	958	818	697	594	506	431	367	313	266	227	193	165	140	119	102	87
Manyberries - Total	486	460	435	412	389	368	348	330	312	295	279	264	250	236	224	212	200	189
Other	1000	952	829	721	626	545	473	411	358	311	270	235	204	177	154	134	116	101
Pipeline Total	**2506**	**2432**	**2223**	**1951**	**1713**	**1507**	**1329**	**1173**	**1038**	**920**	**817**	**727**	**648**	**579**	**519**	**466**	**419**	**378**

Norcen Energy Resources Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Joarcam - Viking	5519	4994	4354	3651	3062	2568	2153	1806	1514	1270	1065	893	749	370	0	0	0	0
Pipeline Total	**5519**	**4994**	**4354**	**3651**	**3062**	**2568**	**2153**	**1806**	**1514**	**1270**	**1065**	**893**	**749**	**370**	**0**	**0**	**0**	**0**

LIGHT CRUDE OIL

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Peace River Oil Pipe Line Co. Ltd.																		
Goose River - BHL	6534	6405	6278	5913	5347	4835	4373	3954	3576	3233	2924	2644	2391	2162	1955	1768	1599	1446
Kaybob - BHL A	11088	10869	10653	10041	9093	8234	7456	6752	6114	5537	5014	4540	4111	3723	3371	3053	2765	2503
Kaybob South - Triassic A	14703	13660	12262	11007	9880	8869	7961	7146	6415	5758	5168	4639	4164	3738	3355	3012	2704	2427
Nipisi - Gilwood A(39%)	23702	22773	20563	17412	14744	12484	10571	8951	7579	6418	5434	4601	3896	3299	2794	2365	2003	1696
Simonette - D-3	7739	7060	6440	5875	5359	4889	4460	4069	3712	3386	3089	2818	2570	2345	2139	1951	1780	1624
Snipe Lake - BHL	8193	7793	7413	6964	6459	5991	5557	5154	4780	4434	4112	3814	3538	3281	3043	2823	2618	2428
Sturgeon Lake - D-3	2448	2168	1920	1701	1507	1334	1182	1047	927	821	727	644	570	505	447	396	351	311
Sturgeon Lake South - D-3	19316	18010	16556	15000	13591	12313	11156	10108	9158	8297	7517	6811	6171	5591	5065	4589	4158	3767
Utikuma - KR SAND A (16%)	972	934	897	833	747	669	600	538	482	432	387	347	311	279	250	224	201	180
Other	13792	13384	12988	12605	12041	11319	10641	10004	9404	8841	8311	7813	7345	6905	6492	6103	5737	5393
Pipeline Total	**108491**	**103060**	**95976**	**87355**	**78771**	**70943**	**63961**	**57726**	**52151**	**47161**	**42689**	**38677**	**35073**	**31833**	**28916**	**26289**	**23919**	**21779**
Pembina Pipe Line Ltd.																		
Pembina - Cardium	64218	59142	54703	50794	47330	44243	41478	38991	36743	34703	32846	31148	29593	28163	26845	25626	24498	23450
Pembina - Keystone Belly River B	8712	8540	8370	7866	7080	6373	5736	5163	4647	4183	3765	3389	3050	2745	2471	2224	2002	1802
Willesden Green - Cardium A(70%)	9009	8831	8656	8484	8213	7854	7516	7196	6893	6607	6336	6079	5836	5605	5386	5178	4980	4792
Other	11880	11645	11414	11028	10499	9996	9517	9061	8627	8213	7819	7445	7088	6748	6425	6117	5824	5545
Pipeline Total	**93821**	**88159**	**83145**	**78173**	**73124**	**68468**	**64248**	**60412**	**56911**	**53707**	**50767**	**48063**	**45568**	**43263**	**41128**	**39147**	**37305**	**35590**
Rainbow Pipe Line Company, Ltd.																		
Mitsue - Gilwood A	52251	47118	42488	38314	34550	31155	28094	25334	22845	20601	18577	16752	15106	13622	12283	11076	9988	9007
Nipisi - Gilwood A(61%)	37073	35619	32166	27243	23073	19541	16550	14017	11871	10054	8515	7212	6108	5173	4381	3710	3142	2661
Rainbow - KR A	10500	10500	10500	10500	10202	8739	7372	6220	5247	4427	3735	3151	2658	2243	1892	1596	1346	1136
Rainbow - KR B	27000	27000	27000	27000	25128	21009	17548	14657	12243	10226	8541	7134	5959	4977	4157	3472	2900	2422
I.S. No. 1 Other	11880	11645	11414	11188	10386	9117	8004	7026	6168	5415	4754	4173	3663	3216	2823	2478	2176	1910
Rainbow - KR F	17000	17000	17000	17000	16654	14265	11915	9952	8312	6943	5799	4844	4046	3379	2823	2358	1969	1645
Rainbow - KR AA	14000	13972	13553	13022	12511	11941	10322	8621	7201	6015	5024	4196	3505	2927	2445	2042	1706	1425
I.S. No. 11 Other	2971	2557	2201	1784	1355	1030	782	594	451	343	260	198	150	112	0	0	0	0
I.S. No. 2 Total	5500	5500	5500	5091	4262	3567	2985	2499	2091	1750	1465	1226	1026	858	718	601	503	421
Rainbow Other	10972	10917	10863	10809	10109	8874	7790	6839	6004	5270	4627	4061	3565	3130	2747	2412	2117	1859
Rainbow South - KR A	3300	3300	3300	3299	3018	2521	2105	1758	1469	1227	1024	856	715	597	498	416	348	290
Rainbow South - KR B	6100	6100	6100	6100	5795	4867	4065	3395	2836	2369	1978	1652	1380	1153	963	804	671	561
Rainbow South - KR E	4189	4168	4147	4127	3831	3312	2864	2476	2141	1851	1600	1384	1196	1034	894	773	668	578
Utikuma Keg River A(84%)	5105	4905	4712	4373	3915	3505	3139	2810	2516	2253	2017	1806	1617	1448	1296	1161	1039	931
Virgo - Total	4244	3546	2962	2474	2066	1726	1441	1204	1005	840	701	586	489	408	341	285	57	0
Zama - Total	9800	9768	8616	7125	5892	4872	4029	3332	2755	2278	1884	1558	552	0	0	0	0	0
Other	10800	10800	10800	10800	10800	10800	10751	9550	8057	6797	5734	4838	4081	3443	2905	2451	2067	1744
Pipeline Total	**232689**	**224420**	**213327**	**200253**	**183554**	**160848**	**139765**	**120292**	**103221**	**88666**	**76244**	**65633**	**55825**	**47728**	**41175**	**35643**	**30707**	**26595**

LIGHT CRUDE OIL

Rangeland Pipeline Company Limited

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Ferrier - Cardium D	2100	2100	2043	1794	1559	1355	1178	1024	890	774	673	585	508	442	384	334	290	252
Ferrier - Cardium E	2112	2137	2150	2150	2150	2130	2006	1878	1763	1658	1564	1477	1398	1326	1259	1197	1141	1088
Gilby - Jurassic B	2885	2856	2828	2689	2455	2241	2046	1868	1705	1557	1421	1297	1184	1081	987	901	822	751
Gilby - Mannville B	1050	1150	1250	1300	1300	1297	1251	1190	1132	1077	1025	976	929	884	841	801	763	726
Gilby - Viking A	576	532	491	448	404	364	329	296	267	241	217	196	177	159	144	130	117	105
Innisfail - D-3	11529	9847	8225	6870	5738	4793	4003	3344	2793	2333	1948	1627	1359	1135	948	792	661	552
Medicine River - Glauconitic A	1592	1576	1560	1498	1395	1299	1209	1126	1048	976	909	846	788	734	683	636	592	551
Medicine River - Jurassic A	1633	1601	1459	1233	1042	881	745	630	532	450	380	321	272	230	194	164	5	0
Medicine River - Jurassic D	1592	1528	1422	1323	1231	1145	1066	992	923	859	799	744	692	644	599	557	519	483
Sundre - Rundle A	3024	2699	2408	2149	1918	1712	1527	1363	1216	1085	969	864	771	688	614	548	489	436
Willesden Green - Cardium A(30%)	3861	3784	3709	3636	3520	3366	3221	3084	2955	2832	2716	2606	2502	2403	2309	2220	2136	2055
Other	22658	21988	21338	20708	20096	18837	17043	15420	13951	12622	11420	10332	9348	8458	7652	6923	6264	5667
Pipeline Total	**54616**	**51802**	**48887**	**45802**	**42813**	**39427**	**35630**	**32220**	**29181**	**26470**	**24046**	**21877**	**19933**	**18188**	**16620**	**15209**	**13804**	**12672**

Texaco Exploration Canada Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Bonnie Glen - D-3A	105715	97587	79880	57492	41378	29780	21433	15426	11102	7990	5751	4139	2979	2144	1543	1110	571	0
Glen Park - D-3A	3140	2841	2571	2249	1900	1606	1356	1146	968	818	691	584	493	417	352	297	251	212
Westerose - D-3	22434	21340	19315	16607	14278	12276	10555	9075	7803	6709	5768	4959	4264	3666	3152	2710	2330	2003
Wizard Lake - D-3A	70229	66804	56941	43224	32812	24907	18907	14352	10895	8270	6278	4765	3617	2746	2084	1582	1201	911
Other	278	275	273	270	267	265	237	191	154	124	100	80	65	52	42	34	26	0
Pipeline Total	**201798**	**188849**	**158982**	**119844**	**90637**	**68836**	**52491**	**40192**	**30924**	**23913**	**18589**	**14530**	**11420**	**9026**	**7175**	**5735**	**4381**	**3128**

Trans-Prairie Pipelines Ltd.: Boundary Lake South

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Boundary Lake South - Triassic C	479	479	478	463	433	405	379	355	332	311	291	272	255	238	223	209	195	183
Boundary Lake South - Triassic E	4257	4172	4090	3818	3390	3010	2673	2373	2107	1871	1661	1475	1310	1163	1033	917	814	723
Other	379	379	379	378	378	349	296	252	214	182	155	132	112	95	81	69	58	50
Pipeline Total	**5116**	**5031**	**4948**	**4659**	**4202**	**3765**	**3349**	**2981**	**2655**	**2365**	**2108**	**1880**	**1678**	**1498**	**1338**	**1195**	**1069**	**956**

LIGHT CRUDE OIL

Twining Pipeline Division

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Twining - Rundle A and LM A	3940	3824	3711	3369	2869	2462	2127	1849	1616	1420	1254	1112	990	885	794	715	646	585
Twining North - Rundle	1325	1375	1372	1240	1110	995	891	798	715	640	574	514	460	412	369	331	296	265
Other	278	275	273	265	253	242	232	222	212	204	195	187	180	173	166	159	153	147
Pipeline Total	**5544**	**5474**	**5356**	**4874**	**4234**	**3700**	**3251**	**2870**	**2544**	**2265**	**2023**	**1814**	**1631**	**1471**	**1330**	**1206**	**1097**	**999**

Valley Pipe Line

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Turner Valley - Rundle & Shallow	3283	3155	2974	2750	2543	2351	2174	2010	1859	1719	1589	1469	1359	1256	1162	1074	993	918
Pipeline Total	**3283**	**3155**	**2974**	**2750**	**2543**	**2351**	**2174**	**2010**	**1859**	**1719**	**1589**	**1469**	**1359**	**1256**	**1162**	**1074**	**993**	**918**

Truck and Tank Car

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Pipeline Total	**424**	**403**	**383**	**365**	**347**	**330**	**279**	**208**	**155**	**116**	**86**	**64**	**48**	**36**	**26**	**10**	**0**	**0**
Alberta Total	**1290234**	**1194005**	**1076290**	**946343**	**830544**	**724526**	**632888**	**554031**	**486811**	**429568**	**380580**	**338460**	**301100**	**268749**	**241065**	**217357**	**195765**	**175419**

SASKATCHEWAN

Westspur - Medium Pipe Line - Batched Light

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Flat Lake - Ratcliffe, Vol. Unit No. 1	1325	1221	1125	1037	956	881	812	748	689	635	585	539	497	458	422	389	358	330
Freda Lake - Ratcliffe	344	316	290	266	244	224	205	188	173	159	145	133	122	112	103	94	87	79
Sherwood - Frobisher	816	734	660	594	534	481	433	389	350	315	283	255	229	206	186	167	150	135
Skinner Lake - Ratcliffe	284	273	257	237	219	202	187	172	159	147	135	125	115	107	98	91	84	77
Pipeline Total	**2770**	**2545**	**2334**	**2135**	**1954**	**1789**	**1638**	**1499**	**1373**	**1257**	**1151**	**1054**	**966**	**885**	**811**	**743**	**681**	**624**

LIGHT CRUDE OIL

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Westspur Pipe Line Company - S.E. Sask. Light																		
Alida East - Alida, Unit	454	424	396	369	345	322	301	281	262	245	229	213	199	186	174	162	151	141
Carnduff - Midale, East Unit	731	659	593	535	482	434	391	353	318	286	258	232	201	0	0	0	0	0
Elmore - Frobisher Vol. Unit	1190	1131	1063	985	914	847	786	728	675	626	581	538	499	463	429	398	369	342
Ingoldsby - Frobisher Alida, Vol. Unit	913	845	784	730	681	637	597	561	527	497	469	444	420	399	379	360	343	327
Kenosee - Tilston, Vol. Unit	1890	1871	1693	1394	1149	946	780	642	529	436	359	296	244	201	165	0	0	0
Parkman - Tilston Souris Valley	1190	1078	977	885	802	726	658	596	540	489	443	402	364	330	299	271	79	0
Queensdale East-Frobisher Alida, Non-Unit	2342	2140	1955	1786	1632	1491	1362	1245	1137	1039	949	867	792	724	662	604	552	504
Rosebank - Frobisher Alida, Vol. Unit No. 1	1098	950	822	711	616	533	461	399	345	299	258	223	193	167	40	0	0	0
Steelman - Midale, Unit 1A	3555	3281	3029	2796	2580	2382	2198	2029	1873	1729	1595	1473	1359	1254	1158	1069	986	910
Steelman - Midale, Unit II	2487	2274	2080	1902	1739	1590	1454	1330	1216	1112	1017	930	850	778	711	650	595	544
Steelman - Midale, Unit III	1624	1478	1327	1192	1070	961	862	774	695	624	560	503	452	405	364	327	293	263
Steelman - Midale, Unit IV	2820	2629	2418	2192	1988	1803	1635	1482	1344	1219	1105	1002	908	824	747	677	614	557
Steelman - Midale, Unit VI	2655	2369	2114	1886	1683	1501	1340	1195	1066	951	849	757	676	603	538	480	428	382
Willmar - Frobisher Alida, Non-Unit	1530	1400	1280	1171	1071	979	896	819	749	685	627	573	524	479	438	401	367	335
Workamn - Forbisher, Vol. Unit No. 1	805	723	649	583	523	469	421	378	340	305	274	246	220	85	0	0	0	0
Other	18060	16839	15701	14407	13006	11740	10598	9567	8636	7795	7037	6352	5734	5176	4672	4218	3807	3437
Pipeline Total	**43350**	**40099**	**36887**	**33532**	**30287**	**27370**	**24747**	**22386**	**20261**	**18345**	**16618**	**15059**	**13645**	**12081**	**10782**	**9623**	**8591**	**7748**
Saskatchewan Total	**46121**	**42644**	**39221**	**35668**	**32242**	**29159**	**26385**	**23886**	**21634**	**19602**	**17769**	**16114**	**14611**	**12966**	**11593**	**10366**	**9272**	**8372**
MANITOBA																		
Trans-Prairie Pipelines Ltd.																		
Daly - Mississippian	1207	1125	1034	936	847	767	694	628	568	514	466	421	381	345	312	283	256	232
North Virden Scallion - Mississippian	4616	4268	3947	3649	3374	3120	2885	2668	2467	2281	2109	1950	1803	1667	1541	1425	1318	1218
Routledge - Mississippian	927	864	775	667	574	494	425	366	315	271	233	111	0	0	0	0	0	0
Virden Roselea - Mississippian	2673	2527	2388	2257	2134	2017	1906	1802	1703	1610	1521	1438	1359	1285	1214	1148	1085	1025
Other	854	804	714	598	500	419	350	293	245	205	171	143	120	56	0	0	0	0
Pipeline Total	**10279**	**9590**	**8860**	**8109**	**7431**	**6818**	**6262**	**5758**	**5300**	**4883**	**4502**	**4066**	**3665**	**3354**	**3069**	**2856**	**2659**	**2476**
Manitoba Total	**10279**	**9590**	**8860**	**8109**	**7431**	**6818**	**6262**	**5758**	**5300**	**4883**	**4502**	**4066**	**3665**	**3354**	**3069**	**2856**	**2659**	**2476**
ONTARIO																		
Ontario - Total	**1531**	**1401**	**1283**	**1174**	**1075**	**984**	**901**	**825**	**755**	**691**	**633**	**579**	**530**	**485**	**444**	**407**	**372**	**341**

HEAVY CRUDE OIL

ALBERTA

Bow River Pipe Lines Ltd.: Heavy

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Bantry - Mannville A	3804	3618	3442	3209	2932	2680	2448	2237	2044	1868	1707	1559	1425	1302	1190	1087	993	908
Countess - Upper Mannville B	1352	1262	1115	929	774	645	538	448	374	311	260	216	180	150	125	79	0	0
Countess - Upper Mannville D	6850	7000	6101	4565	3416	2556	1912	1431	1070	801	599	448	335	170	0	0	0	0
Countess - Upper Mannville H	3459	3193	2835	2418	2062	1758	1499	1278	1090	929	793	676	576	491	419	357	304	260
Countess - Upper Mannville O	1533	1407	1292	1186	1089	999	917	842	773	710	651	598	549	504	462	424	390	358
Grand Forks - Upper Mannville B	1470	1371	1239	1121	1013	916	828	749	677	612	554	501	453	409	370	334	302	273
Grand Forks - Lower Mannville D	9300	9588	8689	7389	6284	5344	4545	3865	3287	2795	2377	2022	1719	1462	1243	1057	899	764
Grand Forks - Lower Mannville K	2673	2407	1985	1637	1350	1113	918	757	624	515	425	350	289	238	196	162	133	110
Hays - Lower Mannville A	1601	1420	1260	1087	913	766	643	539	452	380	318	267	224	188	71	0	0	0
Lathom - Upper Mannville A	2462	2238	1902	1616	1373	1167	991	842	715	608	516	439	373	317	269	228	194	165
Taber - Mannville D	1980	1940	1803	1585	1394	1225	1077	947	833	732	644	566	498	438	385	338	297	261
Taber South - Mannville B	1191	998	799	610	466	356	272	207	158	121	21	0	0	0	0	0	0	0
Other	11940	11821	11157	10028	9014	8102	7283	6546	5884	5289	4754	4273	3841	3452	3103	2789	2507	2254
Pipeline Total	**49620**	**48269**	**43623**	**37387**	**32085**	**27634**	**23878**	**20696**	**17989**	**15677**	**13624**	**11920**	**10467**	**9126**	**7838**	**6862**	**6025**	**5356**

BP Exploration Canada Limited

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Chauvin - Mannville A	581	535	493	455	419	386	356	328	303	279	257	237	218	201	185	171	158	145
Chauvin South - Sparky A&B	970	1020	1020	1020	1007	952	896	844	795	749	705	664	625	589	555	522	492	463
Chauvin South - Sparky E	351	334	311	284	259	237	216	197	180	165	150	137	125	114	104	95	87	79
Chauvin South - Sparky H	931	894	828	738	658	587	523	466	416	370	330	294	262	234	208	186	166	148
Chauvin South - Lloydminster D	226	202	180	160	143	127	113	101	90	80	72	64	57	51	45	40	36	32
Other	1060	1100	1047	945	853	771	696	628	567	512	462	418	377	340	307	278	251	226
Pipeline Total	**4120**	**4086**	**3880**	**3604**	**3342**	**3062**	**2803**	**2568**	**2353**	**2157**	**1979**	**1816**	**1667**	**1532**	**1408**	**1294**	**1191**	**1096**

Husky Pipeline Ltd. & Manito Pipelines Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Lloydminster - Sparky C and GP A	737	711	675	630	588	549	512	478	446	416	389	363	339	316	295	275	257	240
Lloydminster - Sparky and GP C	1980	1940	1859	1740	1628	1523	1426	1334	1249	1168	1094	1023	958	896	839	785	734	687
Viking Kinsella - Wainwright B	9504	9316	8385	6909	5693	4691	3865	3185	2624	2162	1782	1468	1209	997	821	676	557	459
Wainwright - Wainwright & Sparky A	7487	7265	6761	6026	5372	4788	4268	3804	3391	3023	2694	2402	2141	1908	1701	1516	1351	1204
Wildmere - Lloydminster A & Sparky B	2089	2068	2048	1971	1844	1725	1614	1509	1412	1321	1236	1156	1081	1012	946	885	828	775
Other	4653	4561	4200	3628	3134	2707	2339	2020	1745	1507	1302	1125	971	839	725	626	541	467
Pipeline Total	**26451**	**25864**	**23930**	**20907**	**18261**	**15986**	**14026**	**12334**	**10870**	**9601**	**8498**	**7539**	**6702**	**5970**	**5329**	**4766**	**4271**	**3835**

HEAVY CRUDE OIL

Truck and Tank Car

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Cessford - Total	3217	3154	2954	2641	2362	2112	1888	1688	1510	1350	1207	1079	965	863	771	690	617	551
Other	2462	2390	2319	2250	2129	1964	1811	1670	1540	1420	1309	1207	1113	1027	947	873	805	742
Pipeline Total	**5680**	**5544**	**5273**	**4892**	**4491**	**4076**	**3699**	**3358**	**3050**	**2770**	**2517**	**2287**	**2079**	**1890**	**1718**	**1563**	**1422**	**1294**
Alberta Total	**85872**	**83765**	**76709**	**66791**	**58182**	**50759**	**44408**	**38957**	**34263**	**30207**	**26619**	**23563**	**20916**	**18519**	**16295**	**14486**	**12910**	**11582**

SASKATCHEWAN

Husky Pipeline Ltd. & Manito Pipelines Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Aberfeldy - Sparky, Aberfeldy Unit	3785	3564	3213	2768	2385	2055	1770	1525	1314	1132	975	840	724	624	537	463	399	135
South Aberfeldy - Sparky, Voluntary Unit	1489	1375	1233	1073	935	814	708	617	537	467	407	354	308	268	234	132	0	0
Dulwich - Sparky	686	659	626	589	554	521	490	460	433	407	383	360	338	318	299	281	265	249
Epping - Sparky and G.P., Non-Unit	1496	1395	1269	1125	997	884	784	695	616	546	484	429	380	337	62	0	0	0
South Epping - Sparky and G.P., Unit No. 1	2048	1885	1678	1493	1328	1182	1052	936	833	741	660	587	522	465	414	368	327	291
S.W. Epping Sparky Vol. Unit No. 1	926	881	820	745	678	617	561	510	464	422	384	349	317	289	262	239	217	78
Furness - Sparky	309	272	239	211	185	163	143	126	111	98	86	75	66	58	40	0	0	0
Golden Lake North - Waseca & Sparky, Vol. Unit	1577	1428	1280	1147	1028	921	825	740	663	594	532	477	427	383	343	308	276	247
Golden Lake North - Waseca & Sparky, Non-Unit	689	582	491	414	350	295	249	210	177	150	126	96	0	0	0	0	0	0
Golden Lake South - Sparky	735	706	645	559	485	421	365	317	275	238	207	179	155	135	117	101	88	15
Golden Lake South - Waseca	1989	1873	1686	1447	1242	1066	915	786	674	579	497	426	366	314	270	231	199	170
Gully Lake - Waseca, Vol. Unit No. 1	843	773	709	650	597	547	502	460	422	387	355	326	299	274	251	231	212	194
Gully Lake - Waseca, Non-Unit	612	559	511	467	427	391	357	326	298	273	249	228	208	191	174	159	145	133
Lashburn - Waseca, Vol. Unit	337	315	293	273	255	237	221	206	192	179	167	156	145	135	126	117	109	87
Lone Rock - Sparky	274	246	220	197	177	158	142	127	114	102	91	82	73	66	59	53	2	0
Tangleflags (Total)	3635	3510	3227	2819	2463	2152	1881	1643	1436	1254	1096	958	837	731	639	558	488	426
Other	7029	6890	6341	5470	4719	4071	3512	3029	2613	2254	1945	1677	1447	1248	1077	929	801	691
Pipeline Total	**28469**	**26921**	**24489**	**21458**	**18813**	**16504**	**14486**	**12723**	**11181**	**9832**	**8652**	**7608**	**6623**	**5844**	**4912**	**4176**	**3533**	**2722**

HEAVY CRUDE OIL

Bow River Pipe Lines Ltd. (Heavy Blend)

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Coleville - Bakken	3901	3674	3405	3103	2828	2577	2349	2141	1951	1778	1621	1477	1346	1227	1118	1019	929	846
Dodsland - Viking, Eagle Lake, Vol. Unit	1156	1044	950	870	802	743	691	645	604	568	536	507	480	456	434	414	395	378
Dodsland - Viking, Gleneath Unit	1205	1158	1113	1056	990	928	870	815	764	716	671	629	590	553	518	486	455	427
Eureka - Viking, South Unit	794	762	724	680	638	599	563	528	496	465	437	410	385	362	339	319	299	281
North Hoosier - Bakken, Vol. Unit	816	754	696	642	593	548	505	467	431	398	367	339	313	289	267	246	227	210
North Hoosier - Basal Blairmore, Vol. Unit	455	410	370	333	300	270	243	219	197	178	160	144	130	117	105	95	85	14
Smiley Dewar - Viking	1753	1663	1578	1497	1420	1348	1279	1213	1151	1092	1036	983	933	885	839	796	756	717
Other	3123	2827	2507	2223	1972	1749	1551	1375	1220	1082	959	851	755	669	593	526	467	414
Pipeline Total	**13207**	**12296**	**11345**	**10408**	**9547**	**8765**	**8054**	**7407**	**6818**	**6281**	**5791**	**5344**	**4935**	**4561**	**4218**	**3905**	**3617**	**3290**

South Saskatchewan Pipe Line Company

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Battrum - Roseray, Unit No. 1	2514	2350	2197	2053	1919	1794	1677	1568	1466	1370	1281	1197	1119	1046	978	914	854	799
Cantuar Main - Cantuar, Unit	2439	2143	1883	1655	1455	1278	1123	987	867	762	670	589	517	455	399	351	226	0
Dollard - Upper Shaunavon, Unit	5267	4654	4113	3634	3212	2838	2508	2216	1958	1730	1529	1351	1194	1055	932	824	728	643
Fosterton - Roseray, Main Unit	3084	2864	2660	2470	2294	2130	1978	1837	1706	1585	1472	1367	1269	1179	1095	1016	944	877
Gull Lake North - Upper Shaunavon, Unit	1199	1051	922	808	709	621	545	478	419	367	322	282	247	217	25	0	0	0
Instow - Upper Shaunavon, Unit	3780	3372	3009	2684	2395	2137	1906	1701	1517	1354	1208	1078	961	858	765	683	609	543
Main Success - Roseray, Unit	687	626	570	520	473	431	393	358	326	297	271	246	225	50	0	0	0	0
North Premier - Roseray, Unit No. 3	1126	912	739	598	484	392	317	257	101	0	0	0	0	0	0	0	0	0
Rapdan - Upper Shaunavon, Unit	2098	1906	1733	1575	1431	1301	1182	1074	976	887	806	733	666	605	550	500	454	413
South Success - Roseray, Unit	1183	1093	1011	935	864	799	739	683	632	584	540	499	462	427	395	365	337	312
Suffield - Upper Shaunavon, Unit No. 2	603	552	506	464	425	389	357	327	300	275	252	230	211	193	177	162	149	136
Verlo - Roseray, Unit	2359	2099	1868	1662	1479	1316	1171	1042	927	825	734	653	581	517	460	409	364	324
Other	16991	15561	14251	13051	11953	10947	10025	9181	8408	7700	7052	6458	5915	5417	4961	4543	4161	3810
Pipeline Total	**43335**	**39192**	**35467**	**32116**	**29099**	**26380**	**23928**	**21715**	**19609**	**17742**	**16141**	**14689**	**13372**	**12023**	**10742**	**9772**	**8831**	**7861**

HEAVY CRUDE OIL

Westspur Pipe Line Company - S.E. Sask. Medium

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Benson - Midale, Unit	846	784	725	671	621	575	533	493	456	422	391	362	335	310	287	266	246	228
Innes - Frobisher	1096	1014	938	868	803	743	687	636	588	544	503	466	431	399	369	341	316	292
Lost Horse Hill - Frobisher Alida, Vol. Unit No. 1	1072	931	809	703	610	530	460	400	347	302	262	227	198	172	149	129	112	97
Midale - Central Midale, Unit	6035	5627	5246	4891	4560	4251	3963	3695	3445	3211	2994	2791	2602	2426	2262	2109	1966	1833
Midale - Central Midale, Non-Unit	1087	1023	939	839	749	669	598	534	477	426	381	340	304	271	242	216	193	173
Viewfield - Frobisher	1066	1001	940	882	828	778	730	686	644	605	568	533	500	470	441	414	389	365
Weyburn - Midale, Unit	17343	16462	15626	14832	14078	13363	12684	12039	11428	10847	10296	9773	9276	8805	8357	7933	7530	7147
Weyburn - Midale, Non-Unit	862	796	704	624	552	489	433	383	339	300	266	235	208	184	163	31	0	0
Other	8055	7586	7026	6397	5824	5303	4828	4396	4002	3644	3318	3020	2750	2504	2280	2075	1890	1720
Pipeline Total	**37467**	**35228**	**32957**	**30710**	**28631**	**26705**	**24920**	**23265**	**21730**	**20305**	**18982**	**17752**	**16608**	**15544**	**14554**	**13518**	**12644**	**11858**
Saskatchewan Total	**122480**	**113637**	**104259**	**94694**	**86091**	**78354**	**71389**	**65112**	**59340**	**54162**	**49567**	**45394**	**41540**	**37973**	**34427**	**31372**	**28627**	**25733**
Canada - Total Light Crude Oil	**1389011**	**1286147**	**1161208**	**1023626**	**900563**	**787981**	**690501**	**606435**	**534559**	**473119**	**420217**	**374080**	**333666**	**298407**	**268057**	**242110**	**218542**	**196487**
Canada - Total Heavy Crude Oil	**208353**	**197402**	**180969**	**161486**	**144273**	**129113**	**115798**	**104069**	**93603**	**84369**	**76187**	**68958**	**62456**	**56493**	**50722**	**45859**	**41537**	**37316**
Canada - Total Crude Oil	**1597364**	**1483549**	**1342177**	**1185112**	**1044836**	**917094**	**806299**	**710504**	**628162**	**557488**	**496404**	**443038**	**396122**	**354900**	**318779**	**287969**	**260079**	**233803**

PENTANES PLUS PRODUCTION
NEB Forecast
b/d

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
From Established Reserves																		
British Columbia																		
Taylor (Westcoast)	3000	3000	2900	2900	2900	2820	2700	2700	2660	2360	2260	1980	1680	1600	1480	1220	1040	980
Total	**3000**	**3000**	**2900**	**2900**	**2900**	**2820**	**2700**	**2700**	**2660**	**2360**	**2260**	**1980**	**1680**	**1600**	**1480**	**1220**	**1040**	**980**
Alberta																		
Bow River Pipe Lines																		
Cessford (HBOG)	112	98	86	76	67	59	51	45	40	35	31	27	24	21	18	16	13	11
Empress (Pacific)	2100	2080	2050	2020	2000	1975	1950	1950	1950	1950	1950	1950	1950	1950	1720	1525	1335	1140
Wayne-Rosedale	117	103	90	80	70	61	54	47	41	37	32	28	25	22	19	16	14	6
Others	500	467	435	408	375	366	341	301	289	271	253	248	231	216	202	189	184	177
Total	**2829**	**2748**	**2661**	**2584**	**2512**	**2461**	**2396**	**2343**	**2320**	**2293**	**2266**	**2253**	**2230**	**2209**	**1959**	**1746**	**1546**	**1334**
Co-ed Pipe Line																		
Cochrane	1400	1400	1400	1400	1400	1345	1285	1245	1140	1030	970	835	760	685	615	570	425	375
Ellerslie (Dome)	166	863	823	802	856	859	862	864	867	825	744	99	100	112	238	249	259	269
Empress (Dome)	1625	1625	1625	1625	1625	1625	1590	1400	1170	945	715	490	250	50	0	0	0	0
Ferrier (Seafort)	178	156	136	119	104	90	79	69	60	53	47	41	36	32	28	22	0	0
Garrington	280	270	234	201	173	149	128	111	95	82	70	61	53	45	38	25	22	19
Minnehik-Buck Lake	1035	1011	990	871	954	870	747	643	556	481	417	362	314	273	237	206	179	156
Pembina (Texaco)	64	61	58	55	52	49	47	45	42	40	38	37	35	33	32	31	29	28
Quirk Creek	798	778	758	737	677	607	546	493	445	403	365	331	301	273	218	193	175	158
Ricinus	1901	1696	1508	1336	1179	1035	611	753	891	881	872	860	786	688	603	528	464	407
Strachan (Aquitaine)	1073	960	854	727	619	529	454	390	335	289	249	215	185	160	135	111	96	82
Strachan (Gulf)	3853	3352	2922	2551	2229	1950	1707	1495	1310	1149	1007	884	775	680	597	524	460	404
Total	**12373**	**12172**	**11308**	**10424**	**9868**	**9108**	**8056**	**7508**	**6911**	**6178**	**5494**	**4215**	**3595**	**3031**	**2741**	**2459**	**2109**	**1898**
Cremona Pipeline																		
Burnt Timber	406	406	406	406	406	406	406	406	403	366	328	293	262	235	210	188	168	151
Carstairs (Home)	3640	3343	2988	2665	2378	2123	1898	1699	1523	1368	1230	1107	998	901	815	737	668	606
Crossfield (Petrogas)	1989	1812	1656	1517	1394	1286	1189	1104	1024	922	826	740	663	591	530	475	427	383
Crossfield East	583	573	531	484	440	400	365	334	307	281	258	238	219	202	188	174	162	151
Harmattan	5704	5548	5396	4975	4885	4771	4656	4435	4011	3654	3263	2727	2277	1905	1597	1341	1128	949
Lone Pine Creek (Can. Sup.)	307	280	241	207	180	156	135	117	102	89	78	68	60	53	47	37	32	28
Lone Pine Creek (HBOG)	1017	958	900	849	790	692	602	525	458	400	349	305	266	233	156	106	95	84
Olds	470	432	397	366	337	311	287	265	246	227	210	195	181	168	156	145	135	125
Others	50	50	50	50	48	44	40	36	33	30	27	25	23	21	19	18	17	16
Total	**14166**	**13402**	**12565**	**11519**	**10858**	**10189**	**9578**	**8921**	**8107**	**7337**	**6569**	**5698**	**4949**	**4309**	**3718**	**3221**	**2832**	**2493**
Federated Pipe Lines																		
Virginia Hills (Shell)	101	100	95	86	78	71	64	58	52	47	43	39	35	32	29	26	24	21
Others	12	12	11	11	11	10	10	10	9	8	7	5	4	4	3	0	0	0
Total	**113**	**112**	**106**	**97**	**89**	**81**	**74**	**68**	**61**	**55**	**50**	**44**	**39**	**36**	**32**	**26**	**24**	**21**

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Gibson Petroleum																		
Acheson	126	130	132	130	125	100	79	62	49	38	30	24	16	12	10	8	6	5
Ferrybank	120	120	120	120	113	100	88	78	69	61	54	47	42	37	33	29	25	22
Niton (Dome)	119	103	89	77	67	58	50	43	37	32	28	24	21	18	4	0	0	0
Okotoks	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	57	52	46
Paddle River	428	428	428	428	428	428	428	428	419	374	332	295	261	232	206	182	162	143
Wilson Creek	174	169	165	161	148	130	115	100	84	74	66	58	52	46	41	36	32	28
Worsley	296	236	189	150	120	96	77	61	49	39	31	25	20	0	0	0	0	0
Others	43	35	28	24	19	16	14	7	6	5	3	0	0	0	0	0	0	0
Total	**1364**	**1279**	**1209**	**1148**	**1078**	**986**	**909**	**837**	**771**	**681**	**602**	**531**	**470**	**403**	**352**	**312**	**277**	**244**
Gulf Alberta Pipe Line																		
Ghost Pine (Gulf)	208	206	204	195	173	153	135	120	106	94	83	73	65	57	51	45	40	35
Ghost Pine (Mobil)	180	218	200	183	172	160	149	135	126	119	111	104	98	89	86	82	75	72
Hussar (CDC)	160	148	137	126	116	107	99	92	85	78	72	67	61	57	52	48	45	41
Mikwan	40	36	32	28	25	22	20	17	15	14	12	11	10	9	8	6	0	0
Nevis (Chevron)	696	576	471	386	316	259	212	174	142	0	0	0	0	0	0	0	0	0
Nevis (Gulf)	1131	1059	985	908	810	705	617	630	540	582	498	428	369	319	278	219	165	130
Penhold	33	31	29	27	25	24	23	21	20	19	18	17	16	15	14	13	13	12
Others	245	240	235	232	226	224	214	204	194	190	182	169	164	159	154	151	149	145
Total	**2693**	**2514**	**2293**	**2085**	**1863**	**1654**	**1469**	**1393**	**1228**	**1096**	**976**	**869**	**783**	**705**	**643**	**564**	**487**	**435**
Imperial Pipe Line - Ellerslie																		
Golden Spike	880	880	880	880	880	880	880	880	880	330	330	330	330	330	330	330	330	330
Others	138	128	111	94	76	64	54	45	39	33	28	24	17	14	12	10	9	8
Total	**1018**	**1008**	**991**	**974**	**956**	**944**	**934**	**925**	**919**	**363**	**358**	**354**	**347**	**344**	**342**	**340**	**339**	**338**
Imperial Pipe Line - Leduc																		
Judy Creek	5411	5326	5236	4817	4293	3830	3420	3057	2736	2451	2198	1973	1773	1594	1435	1293	1166	1052
Leduc - Woodbend	428	402	369	330	290	252	217	186	372	394	419	403	389	376	366	334	319	296
Total	**5839**	**5728**	**5605**	**5147**	**4583**	**4082**	**3637**	**3243**	**3108**	**2845**	**2617**	**2376**	**2162**	**1970**	**1801**	**1627**	**1485**	**1348**
Imperial PipeLine - Redwater																		
Redwater	645	645	593	469	371	293	231	183	144	114	90	71	56	44	35	28	0	0
Total	**645**	**645**	**593**	**469**	**371**	**293**	**231**	**183**	**144**	**114**	**90**	**71**	**56**	**44**	**35**	**28**	**0**	**0**
Murphy Oil																		
Total	**75**	**71**	**69**	**66**	**64**	**61**	**59**	**57**	**55**	**54**	**52**	**50**	**49**	**44**	**39**	**36**	**33**	**30**

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Peace River Oil Pipeline																		
Carson Creek	1744	1715	1689	1631	1515	1394	1227	1111	1009	898	789	694	610	537	473	417	367	324
Dunvegan	1319	1371	1375	1380	1384	1389	1393	1307	1123	966	832	718	620	538	463	395	337	288
Gold Creek	921	834	756	686	622	562	508	450	410	374	341	311	284	259	237	216	144	0
Greencourt	113	113	113	113	113	113	110	96	84	73	64	56	49	42	37	32	28	25
Kaybob	363	358	349	325	299	274	249	225	203	184	167	152	137	124	113	102	91	84
Kaybob South	35136	32057	29170	26461	23918	21527	19287	15719	15048	13182	10986	9184	7712	6494	5480	4639	3934	3334
Simonette (Shell)	242	289	289	281	269	258	233	204	180	158	139	123	109	96	85	76	66	37
Sturgeon Lake South	536	567	561	515	467	423	383	347	314	284	258	233	211	191	173	157	142	129
Whitecourt	253	238	225	214	204	196	181	156	134	116	99	86	74	63	55	47	40	35
Windfall	3641	3331	3054	2808	2589	1532	1507	1481	1403	1067	784	578	427	316	235	175	130	97
Others	30	29	29	28	27	26	25	21	17	14	12	11	10	10	9	8	7	4
Total	**44298**	**40902**	**37610**	**34442**	**31407**	**27694**	**25103**	**21117**	**19925**	**17316**	**14471**	**12146**	**10243**	**8670**	**7360**	**6264**	**5286**	**4357**
Pembina Pipe Line																		
Brazeau (HBOG)	1495	1483	1471	1431	1393	1356	1321	1288	1255	1225	1138	1008	896	797	711	636	569	510
Brazeau (CDC)	467	465	449	433	419	406	373	316	269	230	198	170	147	127	109	95	82	71
Niton (Norcen)	20	16	14	12	10	8	7	6	5	4	3	3	0	0	0	0	0	0
Peco	440	411	377	349	324	301	284	263	234	209	187	166	148	133	112	100	90	81
Willesden Green	145	129	115	102	90	80	72	64	57	51	45	40	36	33	0	0	0	0
Others	221	198	175	155	141	135	131	128	126	112	109	105	98	94	89	83	80	71
Total	**2788**	**2702**	**2601**	**2482**	**2377**	**2286**	**2188**	**2065**	**1946**	**1831**	**1680**	**1492**	**1325**	**1184**	**1021**	**914**	**821**	**733**
Rainbow Pipe Line																		
Mitsue	480	490	497	460	415	375	338	305	275	248	224	202	182	164	148	134	121	109
Nipisi	746	792	830	825	794	682	580	493	419	357	304	258	220	187	159	136	116	99
Swan Hills (Shell)	96	90	85	80	75	71	67	64	61	58	55	52	50	48	45	43	42	40
Total	**1322**	**1372**	**1412**	**1365**	**1284**	**1128**	**985**	**862**	**755**	**663**	**583**	**512**	**452**	**399**	**352**	**313**	**279**	**248**
Rangeland Pipe Line																		
Caroline (Altana)	225	212	201	186	173	162	144	119	98	84	72	62	53	46	35	30	26	23
Caroline (HBOG)	605	558	516	480	448	419	378	330	289	253	222	195	171	150	132	116	102	90
Ferrier (Amerada)	1441	1409	1346	1198	1062	942	830	733	653	581	517	460	410	365	325	288	246	220
Gilby (Texaco)	598	593	563	523	489	455	419	387	359	335	314	297	277	242	208	176	152	132
Gilby (Others)	621	552	491	440	396	359	324	293	267	245	215	191	166	142	88	77	69	61
Innisfail	135	143	151	158	157	137	115	96	81	68	57	47	40	33	28	23	19	16
Joffre (Imperial)	29	30	32	33	33	32	30	28	26	24	22	21	20	19	18	17	16	15
Pincher Creek	910	673	505	384	296	230	181	143	115	92	75	41	34	29	26	22	20	0
Sylvan Lake (Chevron)	247	216	189	166	146	128	111	96	82	73	66	59	53	47	42	38	33	30
Sylvan Lake (HBOG)	429	368	319	279	247	220	196	179	159	147	136	114	97	84	73	64	57	49
Sylvan Lake (Others)	301	269	243	221	202	185	172	160	145	135	127	119	104	90	47	40	35	30
Waterton	9531	9320	8970	9509	9171	8819	8440	7498	6321	5431	4752	4226	3813	3483	3216	2995	2808	2647
Wimborne (Mobil)	677	558	461	381	317	264	220	183	153	127	107	90	76	63	53	44	35	30
Others	200	185	160	145	135	120	108	96	84	75	61	53	48	43	39	35	33	31
Total	**15949**	**15086**	**14147**	**14103**	**13272**	**12472**	**11668**	**10341**	**8832**	**7670**	**6743**	**5975**	**5362**	**4836**	**4330**	**3965**	**3651**	**3374**
Rimbey Pipeline																		
Homeglen - Rimbey	7916	7865	6899	5727	4764	3953	3293	2756	2320	1966	1677	1442	1252	1085	948	804	647	507
Total	**7916**	**7865**	**6899**	**5727**	**4764**	**3953**	**3293**	**2756**	**2320**	**1966**	**1677**	**1442**	**1252**	**1085**	**948**	**804**	**647**	**507**

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Texaco Exploration																		
Bonnie Glen	4435	4482	4532	4487	4124	3719	3311	2984	1966	1894	1855	1840	1844	1821	1597	1404	1257	1148
Total	**4435**	**4482**	**4532**	**4487**	**4124**	**3719**	**3311**	**2984**	**1966**	**1894**	**1855**	**1840**	**1844**	**1821**	**1597**	**1404**	**1257**	**1148**
Valley Pipe Line																		
Jumping Pound	2779	2694	2597	2449	2319	2206	2106	2012	1907	1810	1723	1646	1576	1514	1458	1402	1273	1131
Turner Valley	369	337	308	281	257	235	215	196	179	164	150	137	125	114	105	96	87	80
Wildcat Hills	668	657	649	643	638	635	621	608	542	478	422	373	329	290	256	226	200	176
Total	**3816**	**3688**	**3554**	**3373**	**3214**	**3076**	**2942**	**2816**	**2628**	**2452**	**2295**	**2156**	**2030**	**1918**	**1819**	**1724**	**1560**	**1387**
Truck and Tank Car																		
Boundary Lake South (Imperial)	69	60	52	45	39	34	30	26	22	19	14	12	11	10	9	8	7	1
Edson	1904	1882	1748	1512	1310	1137	988	855	741	643	558	484	421	366	318	277	241	210
Rosevear (Sun)	210	210	210	210	210	210	210	210	210	198	167	140	118	99	83	70	58	49
Niton	119	103	89	77	67	58	50	43	37	32	28	24	21	18	4	0	0	0
Others	675	700	760	825	885	920	960	1020	1090	1200	1220	1240	1260	1110	1050	1000	930	870
Total	**2977**	**2955**	**2859**	**2669**	**2511**	**2359**	**2238**	**2154**	**2100**	**2092**	**1987**	**1900**	**1831**	**1603**	**1464**	**1355**	**1236**	**1130**
Alberta Total	**124616**	**118731**	**111014**	**103161**	**95195**	**86546**	**79071**	**70573**	**64096**	**56900**	**50365**	**43924**	**39019**	**34611**	**30553**	**27102**	**23869**	**21025**
Saskatchewan																		
Total	**729**	**685**	**644**	**605**	**569**	**484**	**411**	**349**	**297**	**252**	**225**	**200**	**178**	**158**	**141**	**125**	**112**	**100**
Total Canada	128345	122416	114558	106666	98664	89850	82182	73622	67053	59512	52850	46104	40877	36369	32174	28447	25021	22105
Less Injection	2750	2500	2250	2000	1750	1500	1250	1000	0	0	0	0	0	0	0	0	0	0
Sub Total	125595	119916	112308	104666	96914	88350	80932	72622	67053	59512	52850	46104	40877	36369	32174	28447	25021	22105
From Reserves Additions	**3752**	**7547**	**12178**	**15087**	**20012**	**25654**	**27880**	**29727**	**30120**	**31450**	**32440**	**32510**	**31200**	**30970**	**30300**	**29700**	**27860**	**26340**
Total	**129347**	**127463**	**124486**	**119753**	**116926**	**114004**	**108812**	**102349**	**97173**	**90962**	**85290**	**78614**	**72077**	**67339**	**62474**	**58147**	**52881**	**48445**

POTENTIAL PRODUCIBILITY FROM OIL SANDS

NEB Forecast

Base Case

(Mb/d)

Year	Miscell-aneous In Situ	GCOS	Syncrude	Syncrude Expansion	Cold Lake* In Situ	3rd* Mining	Undefined Project	Undefined Project	Undefined Project	Undefined Project	Total
1978	7	45	25	-	-	-	-	-	-	-	77
1979	10	45	90	-	-	-	-	-	-	-	145
1980	10	45	100	-	-	-	-	-	-	-	155
1981	15	45	110	-	-	-	-	-	-	-	170
1982	15	45	120	-	-	-	-	-	-	-	180
1983	20	55	125	-	-	-	-	-	-	-	200
1984	25	65	125	-	-	-	-	-	-	-	215
1985	30	65	125	35	-	-	-	-	-	-	255
1986	30	65	125	50	-	-	-	-	-	-	270
1987	30	65	125	60	50	-	-	-	-	-	330
1988	30	65	125	65	100	60	-	-	-	-	445
1989	30	65	125	65	130	90	-	-	-	-	505
1990	30	65	125	65	145	120	-	-	-	-	550
1991	30	65	125	65	145	125	35	-	-	-	590
1992	30	65	125	65	145	125	75	-	-	-	630
1993	30	65	125	65	145	125	125	-	-	-	680
1994	30	65	125	65	145	125	125	35	-	-	715
1995	30	65	125	65	145	125	125	75	-	-	755

* 3rd mining and 1st In Situ plant considered to have equal opportunity to start up in 1987, but because of the magnitude of these projects, it is considered unlikely that both projects will start up in 1987.

POTENTIAL PRODUCIBILITY FROM OIL SANDS

NEB Forecast

High Case

(Mb/d)

Year	Miscell-aneous In Situ	GCOS	Syncrude	Syncrude Expansion	Cold Lake In Situ	3rd Mining	Undefined Project	Undefined Project	Undefined Project	Undefined Project	Total
1978	7	45	25	-	-	-	-	-	-	-	77
1979	10	45	105	-	-	-	-	-	-	-	160
1980	15	45	105	-	-	-	-	-	-	-	165
1981	20	55	110	-	-	-	-	-	-	-	185
1982	25	65	120	-	-	-	-	-	-	-	210
1983	30	65	130	-	-	-	-	-	-	-	225
1984	30	65	130	25	-	-	-	-	-	-	250
1985	30	65	130	50	-	-	-	-	-	-	275
1986	30	65	130	60	35	60	-	-	-	-	380
1987	30	65	130	65	100	90	-	-	-	-	480
1988	30	65	130	65	130	120	-	-	-	-	540
1989	30	65	130	65	145	125	35	-	-	-	595
1990	30	65	130	65	145	125	100	-	-	-	660
1991	30	65	130	65	145	125	130	35	-	-	725
1992	30	65	130	65	215	185	140	100	-	-	930
1993	30	65	130	65	215	185	140	130	35	-	995
1994	30	65	130	65	215	185	140	140	100	-	1070
1995	30	65	130	65	215	185	210	140	130	35	1205

POTENTIAL PRODUCIBILITY FROM OIL SANDS

NEB Forecast

Low Case

(Mb/d)

Year	Miscell-aneous In Situ	GCOS	Syncrude	Syncrude Expansion	Cold Lake In Situ	3rd Mining	Undefined Project	Undefined Project	Undefined Project	Undefined Project	Total
1978	6	45	25	-	-	-	-	-	-	-	76
1979	7	45	90	-	-	-	-	-	-	-	142
1980	8	45	100	-	-	-	-	-	-	-	153
1981	8	45	110	-	-	-	-	-	-	-	163
1982	8	45	120	-	-	-	-	-	-	-	173
1983	6	45	125	-	-	-	-	-	-	-	176
1984	5	45	125	-	-	-	-	-	-	-	175
1985	5	45	125	-	-	-	-	-	-	-	175
1986	5	45	125	-	-	-	-	-	-	-	175
1987	5	45	125	-	-	-	-	-	-	-	175
1988	5	45	125	-	-	-	-	-	-	-	175
1989	5	45	125	-	-	-	-	-	-	-	175
1990	5	45	125	-	-	-	-	-	-	-	175
1991	5	45	125	-	-	-	-	-	-	-	175
1992	5	45	125	-	-	-	-	-	-	-	175
1993	5	45	125	-	-	-	-	-	-	-	175
1994	5	45	125	-	-	-	-	-	-	-	175
1995	5	45	125	-	-	-	-	-	-	-	175

POTENTIAL PRODUCIBILITY OF CRUDE OIL AND EQUIVALENT

Base Case

(Mb/d)

	Light Crude Oil and Equivalent						Heavy Crude Oil						Total Crude Oil and Equivalent					
	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands (Synthetic)	Upgraded Heavy	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrader Feed-Stock	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrading Loss	Total
1978	1389	14	118	70	-	1591	208	9	11	7	-	235	1597	23	129	77	-	1826
1979	1286	34	115	135	-	1570	197	20	12	10	-	239	1483	54	127	145	-	1809
1980	1161	58	111	145	-	1475	181	30	13	10	-	234	1342	88	124	155	-	1709
1981	1024	83	106	155	-	1368	161	40	14	15	-	230	1185	123	120	170	-	1598
1982	901	103	102	165	-	1271	144	52	15	15	-	226	1045	155	117	180	-	1497
1983	788	123	98	180	-	1189	129	59	16	20	-	224	917	182	114	200	-	1413
1984	691	137	91	190	-	1109	116	67	18	25	-	226	807	204	109	215	-	1335
1985	606	151	91	225	45	1118	104	76	11	30	(50)	171	710	227	102	255	(5)	1289
1986	535	164	85	240	45	1069	94	89	12	30	(50)	175	629	253	97	270	(5)	1244
1987	473	170	78	300	45	1066	84	102	13	30	(50)	179	557	272	91	330	(5)	1245
1988	420	176	72	415	45	1128	76	116	13	30	(50)	185	496	292	85	445	(5)	1313
1989	374	178	65	475	45	1137	69	127	14	30	(50)	190	443	305	79	505	(5)	1327
1990	334	182	57	520	45	1138	62	136	15	30	(50)	193	396	318	72	550	(5)	1331
1991	298	189	51	560	45	1143	56	144	16	30	(50)	196	354	333	67	590	(5)	1339
1992	268	192	45	600	45	1150	51	152	17	30	(50)	200	319	344	62	630	(5)	1350
1993	242	195	41	650	45	1173	46	157	17	30	(50)	200	288	352	58	680	(5)	1373
1994	219	195	36	685	45	1180	42	162	17	30	(50)	201	261	357	53	715	(5)	1381
1995	196	195	31	725	45	1192	37	166	17	30	(50)	200	233	361	48	755	(5)	1392

POTENTIAL PRODUCIBILITY OF CRUDE OIL AND EQUIVALENT

High Case

(Mb/d)

	Light Crude Oil and Equivalent						Heavy Crude Oil						Total Crude Oil and Equivalent					
	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands (Synthetic)	Upgraded Heavy	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrader Feed-Stock	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrading Loss	Total
1978	1389	16	118	70	-	1593	208	9	11	7	-	235	1597	25	129	77	-	1828
1979	1286	42	113	150	-	1591	197	20	14	10	-	241	1483	62	127	160	-	1832
1980	1161	75	107	150	-	1493	181	35	17	15	-	248	1342	110	124	165	-	1741
1981	1024	109	101	165	-	1399	161	48	19	20	-	248	1185	157	120	185	-	1647
1982	901	143	97	185	-	1326	144	63	20	25	-	252	1045	206	117	210	-	1578
1983	788	180	93	195	-	1256	129	75	21	30	-	255	917	255	114	225	-	1511
1984	691	214	87	220	-	1212	116	90	22	30	-	258	807	304	109	250	-	1470
1985	606	246	89	245	45	1231	104	104	13	30	(50)	201	710	350	102	275	(5)	1432
1986	535	275	83	350	45	1288	94	121	14	30	(50)	209	629	396	97	380	(5)	1497
1987	473	301	76	450	45	1345	84	137	15	30	(50)	216	557	438	91	480	(5)	1561
1988	420	320	68	510	45	1363	76	153	17	30	(50)	226	496	473	85	540	(5)	1589
1989	374	339	61	565	45	1384	69	168	18	30	(50)	235	443	507	79	595	(5)	1619
1990	334	352	62	630	90	1468	62	184	10	30	(100)	186	396	536	72	660	(10)	1654
1991	298	364	56	695	90	1503	56	195	11	30	(100)	192	354	559	67	725	(10)	1695
1992	268	375	50	900	90	1683	51	203	12	30	(100)	196	319	578	62	930	(10)	1879
1993	242	382	45	965	90	1724	46	217	13	30	(100)	206	288	599	58	995	(10)	1930
1994	219	388	39	1040	90	1776	42	230	14	30	(100)	216	261	618	53	1070	(10)	1992
1995	196	388	33	1175	90	1882	37	236	15	30	(100)	218	233	624	48	1205	(10)	2100

POTENTIAL PRODUCIBILITY OF CRUDE OIL AND EQUIVALENT

Low Case

(Mb/d)

	Light Crude Oil and Equivalent						Heavy Crude Oil						Total Crude Oil and Equivalent					
	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands (Synthetic)	Upgraded Heavy	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrader Feed-Stock	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrading Loss	Total
1978	1389	9	118	70	-	1586	208	7	11	6	-	232	1597	16	129	76	-	1818
1979	1286	24	116	135	-	1561	197	14	11	7	-	229	1483	38	127	142	-	1790
1980	1161	40	113	145	-	1459	181	21	11	8	-	221	1342	61	124	153	-	1680
1981	1024	57	109	155	-	1345	161	28	11	8	-	208	1185	85	120	163	-	1553
1982	901	71	107	155	-	1234	144	33	10	8	-	195	1045	104	117	163	-	1429
1983	788	85	104	165	-	1142	129	37	10	6	-	182	917	122	114	171	-	1324
1984	691	95	99	170	-	1055	116	39	10	5	-	170	807	134	109	175	-	1225
1985	606	104	93	170	-	973	104	44	9	5	-	162	710	148	102	175	-	1135
1986	535	112	88	170	-	905	94	47	9	5	-	155	629	159	97	175	-	1060
1987	473	118	82	170	-	843	84	53	9	5	-	151	557	171	91	175	-	994
1988	420	119	75	170	-	784	76	59	10	5	-	150	496	178	85	175	-	934
1989	374	120	69	170	-	733	69	65	10	5	-	149	443	185	79	175	-	882
1990	334	120	62	170	-	686	62	67	10	5	-	144	396	187	72	175	-	830
1991	298	120	57	170	-	645	56	73	10	5	-	144	354	193	67	175	-	789
1992	268	117	51	170	-	606	51	76	11	5	-	143	319	193	62	175	-	749
1993	242	115	47	170	-	574	46	84	11	5	-	146	288	199	58	175	-	720
1994	219	114	42	170	-	545	42	89	11	5	-	147	261	203	53	175	-	692
1995	196	111	37	170	-	514	37	91	11	5	-	144	233	202	48	175	-	658

ENERGY DEMAND BY SECTOR

NEB Forecast

(trillions of Btu's)

	1978	1980	1985	1990	1995
Residential					
Total Oil	532.1	494.5	469.3	468.7	457.7
Diesel	58.0	54.0	55.1	59.8	63.7
LFO, Kerosene & Stove Oil	451.3	420.6	392.3	383.8	366.4
HFO	22.8	19.9	21.9	25.1	27.6
Natural Gas	326.6	338.0	380.6	441.6	507.5
Electricity	268.9	292.5	352.1	428.9	516.4
Other*	73.5	64.6	66.0	80.3	96.6
Total Energy	1201.1	1189.6	1268.0	1419.5	1578.2
Commercial					
Total Oil	204.5	201.5	203.5	213.3	223.6
Diesel	21.4	23.1	24.5	25.7	26.7
LFO, Kerosene & Stove Oil	92.8	91.4	91.4	94.7	98.1
HFO	90.3	87.0	87.6	92.9	98.8
Natural Gas	314.1	335.6	408.0	473.9	551.7
Electricity	256.5	290.3	403.7	511.0	634.9
Other*	0	0	0	9.8	23.4
Total Energy	775.1	827.4	1015.2	1208.0	1433.6
Industrial					
Total Oil	549.8	573.1	624.2	654.5	732.1
Diesel	140.3	141.7	153.3	165.0	184.3
LFO, Kerosene & Stove Oil	67.3	69.5	75.1	75.9	85.7
HFO	342.2	361.9	395.8	413.6	462.1
Natural Gas	533.0	586.1	692.5	770.6	943.6
Electricity	436.3	480.0	558.1	657.5	775.6
Other*	275.0	293.0	325.6	347.5	383.1
Total Energy**	1794.1	1932.2	2200.4	2430.1	2834.4
Petrochemical					
Total Oil	149.3	187.5	290.8	338.5	338.5
Natural Gas	153.6	190.1	257.6	290.5	307.1
Other*	23.6	23.6	23.6	35.6	35.6
Total Energy	326.5	401.2	572.0	664.6	681.2

* includes all LPG's, coal and renewable energy.

** Total energy for the industrial sector excludes requirements for the production of petrochemicals; and includes coal used to produce coke and coke oven gas.

ENERGY DEMAND BY SECTOR

NEB Forecast

(trillions of Btu's)

	1978	1980	1985	1990	1995
Transportation					
Total Oil	1669.2	1749.7	1887.8	2006.3	2152.8
Total Energy	1671.6	1752.0	1890.2	2008.7	2155.2
Road					
Total Oil	1330.8	1375.5	1424.9	1477.1	1551.3
Motor Gasoline	1220.9	1242.7	1216.0	1174.9	1145.3
Diesel	109.9	132.8	208.9	302.2	406.0
Total Energy	1330.8	1375.5	1424.9	1477.1	1551.3
Rail					
Total Oil	97.3	102.2	116.1	129.0	145.9
Diesel	87.3	91.7	104.0	115.5	130.6
LFO & Kerosene	2.7	2.9	3.5	4.1	4.8
HFO	7.3	7.6	8.6	9.4	10.5
Coal	1.6	1.5	1.4	1.3	1.2
Total Energy	98.9	103.7	117.5	130.3	147.1
Air					
Total Oil	144.9	165.9	219.9	261.9	303.2
Aviation Gasoline	8.3	8.8	8.7	9.7	10.9
Aviation Turbo Fuel	136.6	157.1	211.2	252.2	292.3
Total Energy	144.9	165.9	219.9	261.9	303.2
Marine					
Total Oil	96.2	106.1	126.9	138.3	152.4
Diesel	26.6	29.9	37.7	44.3	52.3
LFO & Kerosene	.6	.7	1.0	1.2	1.5
HFO	69.0	75.5	88.2	92.8	98.6
Coal	.8	.8	1.0	1.1	1.2
Total Energy	97.0	106.9	127.9	139.4	153.6

ENERGY DEMAND BY SECTOR

Export Formula Case

(trillions of Btu's)

	1978	1980	1985	1990	1995
Residential					
Total Oil	594.3	587.0	615.9	635.7	637.2
Total Energy	1285.4	1333.5	1526.7	1725.6	1918.5
Commercial					
Total Oil	228.2	229.7	246.9	272.1	294.3
Total Energy	847.1	933.4	1235.8	1554.9	1896.7
Industrial					
Total Oil	562.9	615.6	761.9	878.6	1023.7
Total Energy	1836.1	2064.4	2626.8	3172.9	3838.0
Petrochemical					
Total Oil	149.3	187.5	290.8	338.5	338.5
Total Energy	326.6	401.2	572.1	664.5	681.2
Transportation					
Total Oil	1806.9	1958.1	2362.7	2807.2	3299.4
Total Energy	1809.8	1960.8	2365.4	2809.9	3302.2
Road					
Total Oil	1447.4	1559.7	1857.3	2212.5	2601.2
Total Energy	1447.4	1559.7	1857.3	2212.5	2601.2
Rail					
Total Oil	99.7	107.6	124.7	140.9	162.2
Total Energy	101.4	109.2	126.3	142.4	163.6
Air					
Total Oil	144.9	165.8	231.4	291.0	356.7
Total Energy	144.9	165.8	231.4	291.0	356.7
Marine					
Total Oil	114.9	125.0	149.3	162.8	179.3
Total Energy	116.1	126.1	150.4	164.0	180.7

Note: Oil data excludes all LPG's

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Canada

Mb/d

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	640.5	649.3	652.1	637.8	616.5	600.8
Light Fuel Oil, Kerosene and Stove Oil	294.4	286.6	280.6	270.1	267.9	265.2
Diesel Fuel Oil	214.7	222.0	230.8	282.6	344.4	418.6
Heavy Fuel Oil	294.9	305.1	310.7	332.6	332.3	367.1
Petrochemical Feedstocks	70.5	79.5	88.5	137.3	159.8	159.8
Other Products	218.6	226.7	234.4	284.6	331.2	378.7
Total All Products	1733.6	1769.2	1797.1	1945.0	2052.1	2190.2
Export Formula Case Total All Products	1856.7	1923.5	1984.6	2335.2	2680.7	3028.1

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

East of the Ottawa Valley

Mb/d

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	227.5	229.6	229.4	217.7	205.4	196.4
Light Fuel Oil, Kerosene and Stove Oil	173.7	170.4	168.0	164.7	165.8	166.3
Diesel Fuel Oil	70.4	72.7	74.6	89.3	106.5	126.6
Heavy Fuel Oil	201.1	212.0	216.5	233.6	231.9	260.2
Petrochemical Feedstocks	19.6	19.6	19.6	34.9	34.9	34.9
Other Products	80.5	82.6	84.6	103.5	119.9	136.6
Total All Products	772.8	786.9	792.7	843.7	864.4	921.0
Export Formula Case Total All Products	844.1	872.9	895.5	1034.6	1165.2	1301.5

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

West of the Ottawa Valley

Mb/d

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	413.0	419.7	422.7	420.1	411.1	404.4
Light Fuel Oil, Kerosene and Stove Oil	120.7	116.2	112.6	105.4	102.1	98.9
Diesel Fuel Oil	144.3	149.3	156.2	193.3	237.9	292.0
Heavy Fuel Oil	93.8	93.1	94.2	99.0	100.4	106.9
Petrochemical Feedstocks	50.9	59.9	68.9	102.4	124.9	124.9
Other Products	138.1	144.1	149.8	181.1	211.3	242.1
Total All Products	960.8	982.3	1004.4	1101.3	1187.7	1269.2
Export Formula Case Total All Products	1012.6	1050.6	1089.1	1300.6	1515.5	1726.6

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Atlantic

Mb/d

NEB Forecast	1978	1979	1980	1985	1990	1995
Motor Gasoline	53.2	53.4	53.3	52.8	51.6	49.7
Light Fuel Oil, Kerosene and Stove Oil	49.8	48.5	48.0	49.8	52.2	54.3
Diesel Fuel Oil	24.4	25.2	25.8	29.0	34.1	39.9
Heavy Fuel Oil	85.5	93.0	94.2	98.6	90.5	103.0
Petrochemical Feedstocks	0.5	0.5	0.5	0.5	0.5	0.5
Other Products	17.6	18.1	18.5	22.1	25.9	29.7
Total All Products	231.0	238.7	240.3	252.8	254.8	277.1
Export Formula Case Total All Products	260.9	275.1	281.9	305.4	342.7	375.2

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Quebec

Mb/d

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	151.4	152.9	152.7	142.7	133.1	127.4
Light Fuel Oil, Kerosene and Stove Oil	112.8	111.3	110.0	105.6	104.7	103.4
Diesel Fuel Oil	40.4	41.6	42.6	52.4	62.5	74.3
Heavy Fuel Oil	106.7	110.2	113.4	126.2	132.5	148.1
Petrochemical Feedstocks	19.1	19.1	19.1	34.4	34.4	34.4
Other Products	56.4	57.8	59.1	73.1	84.5	96.1
Total All Products	486.8	492.9	496.9	534.4	551.7	583.7
Export Formula Case Total All Products	524.1	537.6	552.3	660.8	746.8	842.1

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Ontario

Mb/d

NEB Forecast	1978	1979	1980	1985	1990	1995
Motor Gasoline	229.4	232.6	233.6	222.1	206.8	193.4
Light Fuel Oil, Kerosene and Stove Oil	92.7	87.8	83.5	77.5	74.0	71.7
Diesel Fuel Oil	50.7	53.5	56.2	71.8	90.4	112.4
Heavy Fuel Oil	74.6	73.1	74.0	73.5	73.9	76.0
Petrochemical Feedstocks	50.0	59.0	68.0	81.5	104.0	104.0
Other Products	71.3	74.1	77.1	91.3	105.3	119.4
Total All Products	568.7	580.1	592.4	617.7	654.4	676.9
Export Formula Case Total All Products	611.1	632.0	654.6	747.5	856.3	945.9

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Ottawa Valley

Mb/d

NEB Forecast	1978	1979	1980	1985	1990	1995
Motor Gasoline	22.9	23.3	23.4	22.2	20.7	19.3
Light Fuel Oil, Kerosene and Stove Oil	11.1	10.6	10.0	9.3	8.9	8.6
Diesel Fuel Oil	5.6	5.9	6.2	7.9	9.9	12.4
Heavy Fuel Oil	8.9	8.8	8.9	8.8	8.9	9.1
Petrochemical Feedstocks	-	-	-	-	-	-
Other Products	6.5	6.7	7.0	8.3	9.5	10.8
Total All Products	55.0	55.3	55.5	56.5	57.9	60.2
Export Formula Case Total All Products	59.1	60.2	61.3	68.4	75.7	84.2

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Manitoba

Mb/d

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	28.3	28.7	28.8	28.3	27.7	27.6
Light Fuel Oil, Kerosene and Stove Oil	5.7	5.6	5.5	5.0	4.8	4.5
Diesel Fuel Oil	12.5	12.9	13.3	15.8	18.7	21.9
Heavy Fuel Oil	2.6	2.7	2.6	2.6	2.3	2.3
Petrochemical Feedstocks	-	-	-	-	-	-
Other Products	8.1	8.6	9.0	11.2	13.2	15.4
Total All Products	57.2	58.5	59.2	62.9	66.7	71.7
Export Formula Case Total All Products	59.6	61.6	63.5	74.6	86.2	98.7

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Saskatchewan

Mb/d

NEB Forecast	1978	1979	1980	1985	1990	1995
Motor Gasoline	36.8	36.6	35.9	34.8	33.7	32.2
Light Fuel Oil, Kerosene and Stove Oil	7.0	6.8	6.7	6.4	6.5	6.6
Diesel Fuel Oil	16.4	16.5	16.7	19.8	23.6	27.9
Heavy Fuel Oil	0.6	0.4	0.3	0.3	0.3	0.3
Petrochemical Feedstocks	-	-	-	-	-	-
Other Products	6.9	7.2	7.4	9.1	10.9	12.6
Total All Products	67.7	67.5	67.0	70.4	75.0	79.6
Export Formula Case Total All Products	69.0	70.3	71.2	82.5	94.6	107.2

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Alberta

Mb/d

NEB Forecast	1978	1979	1980	1985	1990	1995
Motor Gasoline	73.9	76.3	77.8	82.4	84.4	85.0
Light Fuel Oil, Kerosene and Stove Oil	3.3	3.1	2.9	2.8	2.7	2.6
Diesel Fuel Oil	33.2	34.0	34.7	44.5	55.8	69.0
Heavy Fuel Oil	0.7	0.8	0.9	1.0	1.0	1.0
Petrochemical Feedstocks	0.1	0.1	0.1	20.1	20.1	20.1
Other Products	31.1	32.6	33.9	41.9	49.3	57.2
Total All Products	142.3	146.9	150.3	192.7	213.3	234.9
Export Formula Case						
Total All Products	149.0	156.1	163.0	224.7	266.6	313.7

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

British Columbia

Mb/d

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	65.9	67.1	68.3	72.9	77.3	83.4
Light Fuel Oil, Kerosene and Stove Oil	20.3	20.6	21.0	20.1	20.1	19.4
Diesel Fuel Oil	33.2	34.2	37.1	44.1	53.0	65.4
Heavy Fuel Oil	23.8	24.5	24.9	29.9	31.3	35.8
Petrochemical Feedstocks	0.8	0.8	0.8	0.8	0.8	0.8
Other Products	25.4	26.5	27.5	33.6	39.4	45.2
Total All Products	169.4	173.7	179.6	201.4	221.9	250.0
Export Formula Case Total All Products	171.7	178.8	185.5	224.6	269.0	322.8

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Yukon & N.W.T.

Mb/d

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	1.6	1.7	1.7	1.8	1.9	2.1
Light Fuel Oil, Kerosene and Stove Oil	2.8	2.9	3.0	2.9	2.9	2.7
Diesel Fuel Oil	3.9	4.1	4.4	5.2	6.3	7.8
Heavy Fuel Oil	0.4	0.4	0.4	0.5	0.5	0.6
Petrochemical Feedstocks	-	-	-	-	-	-
Other Products	1.8	1.8	1.9	2.3	2.7	3.1
Total All Products	10.5	10.9	11.4	12.7	14.3	16.3
Export Formula Case Total All Products	11.3	12.0	12.6	15.1	18.5	22.5

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Canada

(Mb/d)

	Gulf	Imperial[1]	Shell[2]	Texaco	NEB
Motor Gasoline					
1978	632	620	631	625	641
1980	652	628	650	639	652
1985	645	602	634	636	638
1990	618	590	595	619	617
1995	604	583	588	599	601
Light Fuel Oil, Kerosene and Stove Oil					
1978	289	286	305	293	294
1980	269	268	299	279	281
1985	232	218	299	262	270
1990	209	184	291	251	268
1995	196	156	299	241	265
Diesel Fuel Oil					
1978	218	218	222	222	215
1980	233	237	250	243	231
1985	298	291	317	293	283
1990	368	352	388	345	344
1995	443	415	471	392	419
Heavy Fuel Oil					
1978	302	296	286	294	295
1980	302	314	294	300	311
1985	300	283	331	310	333
1990	316	295	354	322	332
1995	334	304	392	336	367
Petrochemical Feedstocks					
1978	68	86	82	87	71
1980	99	99	93	95	89
1985	111	114	100	124	137
1990	118	139	121	137	160
1995	124	178	143	149	160
Other Products					
1978	192	211	200	213	219
1980	200	212	215	231	234
1985	227	246	252	272	285
1990	254	285	288	311	331
1995	284	326	328	352	379
Total All Products					
1978	1701	1717	1726	1734	1734
1980	1754	1758	1801	1787	1797
1985	1813	1754	1933	1897	1945
1990	1883	1845	2037	1985	2052
1995	1985	1962	2220	2069	2190

Note: Totals might not add due to rounding.

(1) Imperial's demand numbers for petrochemical feedstocks and for other products were adjusted for 1980-'85-'90- '95 to remove that portion of demand supplied by gas plant liquids. Corresponding adjustments were not made to Imperial's provincial tables due to a lack of data.

(2) Shell's heavy fuel oil forecast was adjusted downward in accordance with supplementary material filed after the inquiry.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Atlantic

(Mb/d)

Motor Gasoline	Gulf	Imperial	Shell (1)	Texaco	Nova Scotia (2)	NEB
1978	53	52	51	52	-	53
1980	55	53	53	53	52	53
1985	58	52	51	52	49	53
1990	58	50	47	50	46	52
1995	59	50	46	48	45	50
Light Fuel Oil, Kerosene and Stove Oil						
1978	49	47	51	50	-	50
1980	46	45	51	47	51	48
1985	42	45	54	41	55	50
1990	42	47	54	40	57	52
1995	41	50	57	40	56	54
Diesel Fuel Oil						
1978	24	24	27	26	-	24
1980	25	27	30	28	26	26
1985	32	33	36	34	36	29
1990	39	42	42	40	43	34
1995	46	45	48	47	49	40
Heavy Fuel Oil						
1978	91	86	78	78	-	86
1980	88	99	77	80	85	94
1985	85	106	90	85	83	99
1990	91	112	94	90	80	91
1995	99	117	108	95	77	103
Petrochemical Feedstocks						
1978	1	-	-	1	-	1
1980	1	-	-	1	-	1
1985	1	-	-	1	-	1
1990	1	-	-	1	-	1
1995	2	-	-	1	-	1
Other Products						
1978	16	16	17	16	-	18
1980	16	17	16	17	15	19
1985	19	22	18	19	16	22
1990	21	28	20	22	17	26
1995	23	30	22	26	18	30
Total All Products						
1978	234	225	224	223	-	231
1980	233	241	227	226	228	240
1985	236	258	249	232	238	253
1990	251	279	257	243	243	255
1995	269	292	281	257	245	277

Note: Totals might not add due to rounding.

(1) Shell's heavy fuel oil forecast was adjusted downward in accordance with supplementary material filed after the inquiry.

(2) 1978 figures not available in Nova Scotia submission.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Quebec

(Mb/d)

Motor Gasoline	Gulf	Imperial	Shell	Texaco	Sun Oil	NEB
1978	149	146	150	148	149	151
1980	153	147	152	150	152	153
1985	146	139	142	150	147	143
1990	137	136	127	147	143	133
1995	132	134	120	143	143	127
Light Fuel Oil, Kerosene And Stove Oil						
1978	113	108	118	110	111	113
1980	107	102	116	103	110	110
1985	95	81	116	95	107	106
1990	87	62	116	90	106	105
1995	84	43	119	85	106	103
Diesel Fuel Oil						
1978	40	41	41	42	37	40
1980	43	43	46	48	40	43
1985	55	50	58	60	46	52
1990	68	59	72	73	53	63
1995	83	65	88	84	62	74
Heavy Fuel Oil						
1978	108	105	110	100	106	107
1980	107	110	115	94	110	113
1985	108	99	127	88	122	126
1990	108	105	137	83	134	133
1995	107	110	149	79	148	148
Petrochemical Feedstocks						
1978	22	22	23	24	-	19
1980	23	26	24	26	-	19
1985	26	35	25	30	-	34
1990	27	47	26	36	-	34
1995	27	61	27	43	-	34
Other Products						
1978	47	51	50	51	-	56
1980	48	55	53	53	-	59
1985	54	66	63	62	-	73
1990	61	79	70	72	-	85
1995	67	95	78	82	-	96
Total All Products						
1978	479	473	492	475	-	487
1980	480	483	506	474	-	497
1985	483	470	531	485	-	534
1990	487	488	548	501	-	552
1995	500	508	581	516	-	584

Note: Totals might not add due to rounding.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Ontario

(Mb/d)

Motor Gasoline	Gulf	Imperial	Shell[1]	Texaco	Sun Oil	NEB
1978	223	219	221	220	225	229
1980	230	220	223	223	236	234
1985	230	207	210	223	229	222
1990	217	203	197	219	222	207
1995	210	201	195	215	222	193
Light Fuel Oil, Kerosene and Stove Oil						
1978	90	93	97	95	95	93
1980	82	86	93	92	95	84
1985	65	61	89	89	94	78
1990	55	45	84	86	94	74
1995	49	35	84	83	94	72
Diesel Fuel Oil						
1978	52	52	53	52	54	51
1980	58	57	60	56	59	56
1985	75	70	79	67	69	72
1990	95	83	101	78	80	90
1995	117	96	127	88	92	112
Heavy Fuel Oil						
1978	76	79	71	85	78	75
1980	79	78	75	93	87	74
1985	78	59	83	100	85	74
1990	87	57	90	107	85	74
1995	96	55	99	115	87	76
Petrochemical Feedstocks						
1978	45	59	57	59	-	50
1980	54	74	62	65	-	68
1985	64	80	64	70	-	82
1990	69	92	64	75	-	104
1995	74	116	65	80	-	104
Other Products						
1978	66	61	61	72	-	71
1980	68	65	65	76	-	77
1985	77	78	75	90	-	91
1990	84	90	86	104	-	105
1995	94	105	99	117	-	119
Total All Products						
1978	552	563	560	583	-	569
1980	570	580	578	605	-	592
1985	588	555	600	639	-	618
1990	608	570	622	669	-	654
1995	640	608	669	698	-	677

Note: Totals might not add due to rounding.

(1) Shell's heavy fuel oil forecast was adjusted downward in accordance with supplementary material filed after the inquiry.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Manitoba

(Mb/d)

	Gulf	Imperial (1)	Shell	Texaco	NEB
Motor Gasoline					
1978	28	-	29	28	28
1980	29	-	30	29	29
1985	27	-	28	27	28
1990	26	-	26	26	28
1995	25	-	25	24	28
Light Fuel Oil, Kerosene and Stove Oil					
1978	6	-	6	6	6
1980	5	-	6	6	6
1985	4	-	6	6	5
1990	4	-	5	5	5
1995	3	-	5	5	5
Diesel Fuel Oil					
1978	12	-	12	13	13
1980	13	-	13	14	13
1985	14	-	16	17	16
1990	16	-	18	20	19
1995	18	-	21	23	22
Heavy Fuel Oil					
1978	3	-	3	3	3
1980	3	-	3	3	3
1985	3	-	3	2	3
1990	3	-	3	2	2
1995	3	-	3	2	2
Petrochemical Feedstocks					
1978	-	-	-	-	-
1980	-	-	-	-	-
1985	-	-	-	-	-
1990	-	-	-	-	-
1995	-	-	-	-	-
Other Products					
1978	7	-	7	6	8
1980	7	-	7	8	9
1985	9	-	7	10	11
1990	10	-	8	11	13
1995	12	-	9	13	15
Total All Products					
1978	55	-	57	56	57
1980	57	-	59	60	59
1985	57	-	60	62	63
1990	57	-	60	64	67
1995	60	-	63	67	72

Note: Totals might not add due to rounding.

(1) Imperial only provided a forecast for the Prairies as a whole.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Saskatchewan

(Mb/d)

Motor Gasoline	Gulf	Imperial[1]	Shell	Texaco	NEB
1978	37	-	36	35	37
1980	37	-	38	36	36
1985	36	-	38	35	35
1990	33	-	35	33	34
1995	31	-	36	31	32
Light Fuel Oil, Kerosene and Stove Oil					
1978	7	-	7	7	7
1980	6	-	6	7	6
1985	5	-	6	6	6
1990	4	-	6	6	7
1995	4	-	6	5	7
Diesel Fuel Oil					
1978	17	-	16	17	16
1980	18	-	18	18	17
1985	22	-	21	20	20
1990	26	-	25	23	24
1995	31	-	29	26	28
Heavy Fuel Oil					
1978	0	-	-	-	1
1980	0	-	-	-	0
1985	0	-	-	-	0
1990	0	-	-	-	0
1995	0	-	-	-	0
Petrochemical Feedstocks					
1978	-	-	-	-	-
1980	-	-	-	-	-
1985	-	-	-	-	-
1990	-	-	-	-	-
1995	-	-	-	-	-
Other Products					
1978	7	-	8	7	7
1980	7	-	8	8	7
1985	8	-	9	10	9
1990	9	-	9	12	11
1995	10	-	9	14	13
Total All Products					
1978	66	-	67	66	68
1980	68	-	70	69	67
1985	70	-	74	71	70
1990	72	-	75	74	75
1995	75	-	80	76	80

Note: Totals might not add due to rounding.

(1) Imperial only provided a forecast for the Prairies as a whole.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Alberta

(Mb/d)

Motor Gasoline	Gulf	Imperial[1]	Shell	Texaco	NEB
1978	72	-	74	73	74
1980	76	-	81	76	78
1985	78	-	87	77	82
1990	79	-	84	74	84
1995	80	-	86	71	85
Light Fuel Oil, Kerosene and Stove Oil					
1978	4	-	4	3	3
1980	3	-	4	3	3
1985	3	-	4	3	3
1990	3	-	3	3	3
1995	2	-	3	3	3
Diesel Fuel Oil					
1978	36	-	35	36	33
1980	41	-	41	39	35
1985	52	-	53	46	45
1990	64	-	63	52	56
1995	77	-	81	57	69
Heavy Fuel Oil					
1978	0	-	-	1	1
1980	0	-	1	1	1
1985	0	-	1	1	1
1990	0	-	1	1	1
1995	0	-	1	1	1
Petrochemical Feedstocks					
1978	-	-	-	2	0
1980	20	-	5	2	0
1985	20	-	10	22	20
1990	20	-	30	24	20
1995	20	-	50	24	20
Other Products					
1978	27	-	39	34	31
1980	28	-	42	40	34
1985	32	-	51	46	42
1990	38	-	63	51	49
1995	43	-	69	56	57
Total All Products					
1978	139	-	152	149	142
1980	168	-	174	161	150
1985	186	-	206	195	193
1990	204	-	244	205	213
1995	223	-	290	212	235

Note: Totals might not add due to rounding.

(1) Imperial only provided a forecast for the Prairies as a whole.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Prairies

(Mb/d)

Motor Gasoline	Gulf	Imperial	Shell	Texaco	NEB
1978	137	136	139	136	139
1980	142	139	149	141	143
1985	141	136	153	139	145
1990	138	134	145	133	146
1995	136	132	147	126	145
Light Fuel Oil, Kerosene and Stove Oil					
1978	17	20	17	16	16
1980	14	18	16	16	16
1985	12	17	16	15	14
1990	11	17	14	14	15
1995	9	17	14	13	15
Diesel Fuel Oil					
1978	65	68	63	66	62
1980	72	75	72	71	65
1985	88	95	90	83	80
1990	106	116	106	95	99
1995	126	149	131	106	119
Heavy Fuel Oil					
1978	3	3	3	4	5
1980	3	3	4	4	4
1985	3	3	4	3	4
1990	3	3	4	3	3
1995	3	3	4	3	3
Petrochemical Feedstocks					
1978	-	4	-	2	0
1980	20	15	5	2	0
1985	20	37	10	22	20
1990	20	72	30	24	20
1995	20	72	50	24	20
Other Products					
1978	41	58	54	47	46
1980	42	59	57	56	50
1985	49	67	67	66	62
1990	57	75	80	74	73
1995	65	83	87	83	85
Total All Products					
1978	260	289	276	271	267
1980	293	309	303	290	276
1985	313	355	340	328	326
1990	333	417	379	343	355
1995	358	456	433	355	387

Note: Totals might not add due to rounding.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - British Columbia

(Mb/d)

Motor Gasoline	Gulf	Imperial(1)	Shell(2)	Texaco	B.C.(3)	NEB
1978	68	67	67	67	67	66
1980	71	69	71	70	71	68
1985	69	68	77	70	75	73
1990	66	67	77	68	78	77
1995	65	66	78	65	82	83
Light Fuel Oil, Kerosene and Stove Oil						
1978	18	18	19	19	23	20
1980	17	17	19	18	24	21
1985	14	14	19	18	26	20
1990	13	13	18	16	28	20
1995	11	11	18	15	30	19
Diesel Fuel Oil						
1978	33	33	34	32	32	33
1980	36	35	37	35	35	37
1985	45	43	49	43	42	44
1990	55	52	58	51	46	53
1995	65	60	70	58	51	65
Heavy Fuel Oil						
1978	24	23	24	26	27	24
1980	24	24	23	28	30	25
1985	26	16	27	32	34	30
1990	27	18	29	37	36	31
1995	28	19	32	42	39	36
Petrochemical Feedstocks						
1978	1	1	1	1	1	1
1980	1	2	1	1	1	1
1985	1	2	1	1	1	1
1990	1	3	1	1	1	1
1995	1	4	1	1	2	1
Other Products						
1978	22	25	20	25	21	25
1980	24	26	22	27	23	28
1985	26	30	27	32	30	34
1990	31	36	31	36	37	39
1995	35	41	37	40	45	45
Total All Products						
1978	166	167	165	170	172	169
1980	173	173	173	179	185	180
1985	181	173	200	196	208	201
1990	191	189	214	209	227	222
1995	205	201	236	221	248	250

Note: Totals might not add due to rounding.

(1) Imperial provided a forecast for the Pacific Region.

(2) Shell's heavy fuel oil forecast was adjusted downward in accordance with supplementary material filed after the inquiry.

(3) Forecast submitted by the Province of British Columbia.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Yukon & N.W.T.

(Mb/d)

Motor Gasoline	Gulf	Imperial (1)	Shell	Texaco	NEB
1978	2	-	2	2	2
1980	2	-	2	2	2
1985	2	-	2	2	2
1990	2	-	2	2	2
1995	3	-	2	2	2
Light Fuel Oil, Kerosene and Stove Oil					
1978	3	-	3	3	3
1980	3	-	4	3	3
1985	3	-	4	4	3
1990	3	-	5	5	3
1995	3	-	6	5	3
Diesel Fuel Oil					
1978	4	-	4	4	4
1980	5	-	4	5	4
1985	5	-	5	6	5
1990	6	-	6	8	6
1995	7	-	7	9	8
Heavy Fuel Oil					
1978	1	-	-	1	0
1980	1	-	-	1	0
1985	1	-	-	2	1
1990	1	-	-	2	1
1995	1	-	-	2	1
Petrochemical Feedstocks					
1978	-	-	-	-	-
1980	-	-	-	-	-
1985	-	-	-	-	-
1990	-	-	-	-	-
1995	-	-	-	-	-
Other Products					
1978	2	-	2	2	2
1980	2	-	2	2	2
1985	2	-	3	3	2
1990	2	-	3	3	3
1995	3	-	4	4	3
Total All Products					
1978	10	-	11	12	11
1980	11	-	12	13	11
1985	12	-	14	17	13
1990	14	-	16	20	14
1995	15	-	19	22	16

Note: Totals might not add due to rounding.

(1) Imperial did not submit Yukon & N.W.T. figures.

CRUDE OILS INCLUDED IN NEB HEAVY CRUDE OIL CATEGORY

- Lloydminster-type blended crude oil delivered to the Interprovincial pipeline system either at Hardisty, Alberta or at Kerrobert, Saskatchewan.
- Wainwright and Viking-Kinsella blended crude oils delivered to the Interprovincial pipeline system at Hardisty, Alberta.
- Chauvin crude oil delivered to the Interprovincial pipeline system through the BP Exploration Canada Limited Chauvin-Hardisty pipeline system.
- Area III medium crude oil in Saskatchewan (Fosterton).
- The Bow River Pipelines Ltd. stream in Alberta, excluding light and medium crude oil normally batched separately.
- Area II blended heavy crude oil in Saskatchewan excluding light crude oil normally batched separately (Smiley-Coleville).
- Area IV medium crude oil in Saskatchewan (Midale-Weyburn).
- Other crude oil with API gravity less than 25° API

1978 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

Comparison of Forecasts

Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	765	742	771	749	773	844
Deduct Product Imports	-	14	20	26	8	8
Add Product Exports	-	2	6	44	22	22
Net Product Transfers Out/(In)	19	27	-	18	10	10
Losses, Industry Use and Other Adjustments	55	51	48	62	53	58
Deduct Gas Plant Butanes Supplied to Refineries	-	-	-	-	-	-
Total Requirements	839	808	805	847	850	926
West of the Ottawa Valley Line						
Total Market Product Sales	936	975	955	985	961	1012
Deduct Product Imports	5	-	6	15	12	12
Add Product Exports	46	200	15	76	38	38
Net Product Transfers Out/(In)	(19)	(27)	-	(18)	(10)	(10)
Losses, Industry Use and Other Adjustments	40	(116)	59	57	43	46
Deduct Gas Plant Butanes Supplied to Refineries	18	16	22	16	25	25
Total Requirements	980	1016	1001	1069	995	1049
Canada						
Total Market Product Sales	1701	1717	1726	1734	1734	1856
Deduct Product Imports	5	14	26	41	20	20
Add Product Exports	46	202	21	120	60	60
Losses, Industry Use and Other Adjustments	95	(65)	107	119	96	104
Deduct Gas Plant Butanes Supplied to Refineries	18	16	22	16	25	25
Total Requirements	1819	1824	1806	1916	1845	1975

1979 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

Comparison of Forecasts

Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	766	760	787	748	787	873
Deduct Product Imports	–	–	25	23	7	7
Add Product Exports	–	2	6	44	18	18
Net Product Transfers Out/(In)	20	15	–	13	9	9
Losses, Industry Use and Other Adjustments	53	52	49	59	54	60
Deduct Gas Plant Butanes Supplied to Refineries	–	–	–	–	–	–
Total Requirements	839	829	817	841	861	953
West of the Ottawa Valley Line						
Total Market Product Sales	958	991	983	1014	982	1051
Deduct Product Imports	3	1	11	17	12	12
Add Product Exports	46	228	6	80	34	34
Net Product Transfers Out/(In)	(20)	(15)	–	(13)	(9)	(9)
Losses, Industry Use and Other Adjustments	40	(141)	62	52	43	46
Deduct Gas Plant Butanes Supplied to Refineries	18	16	22	16	25	25
Total Requirements	1003	1046	1018	1100	1013	1085
Canada						
Total Market Product Sales	1724	1751	1770	1762	1769	1924
Deduct Product Imports	3	1	36	40	19	19
Add Product Exports	46	230	12	124	52	52
Losses, Industry Use and Other Adjustments	93	(89)	111	111	97	106
Deduct Gas Plant Butanes Supplied to Refineries	18	16	22	16	25	25
Total Requirements	1842	1875	1835	1941	1874	2038

1980 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

Comparison of Forecasts

Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	765	770	788	751	793	896
Deduct Product Imports	-	-	19	23	7	7
Add Product Exports	-	2	6	44	19	19
Net Product Transfers Out/(In)	(23)	3	-	12	8	8
Losses, Industry Use and Other Adjustments	53	52	48	59	54	61
Deduct Gas Plant Butanes Supplied to Refineries	-	-	-	-	-	-
Total Requirements	795	827	823	843	867	977

West of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	993	988	1013	1036	1004	1089
Deduct Product Imports	2	1	14	17	13	13
Add Product Exports	17	272	-	80	34	34
Net Product Transfers Out/(In)	23	(3)	-	(12)	(8)	(8)
Losses, Industry Use and Other Adjustments	41	(168)	63	53	44	48
Deduct Gas Plant Butanes Supplied to Refineries	18	16	22	15	28	28
Total Requirements	1054	1072	1040	1125	1033	1122

Canada	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	1758	1758	1801	1787	1797	1985
Deduct Product Imports	2	1	33	40	20	20
Add Product Exports	17	274	6	124	53	53
Losses, Industry Use and Other Adjustments	94	(116)	111	112	98	109
Deduct Gas Plant Butanes Supplied to Refineries	18	16	22	15	28	28
Total Requirements	1849	1899	1863	1968	1900	2099

1985 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

Comparison of Forecasts

Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	773	771	838	771	844	1035
Deduct Product Imports	-	-	35	23	8	8
Add Product Exports	-	2	15	44	16	16
Net Product Transfers Out/(In)	(20)	2	-	6	8	8
Losses, Industry Use and Other Adjustments	53	50	51	60	58	70
Deduct Gas Plant Butanes Supplied to Refineries	-	-	-	-	-	-
Total Requirements	806	825	869	858	918	1121
West of the Ottawa Valley Line						
Total Market Product Sales	1039	983	1095	1126	1101	1300
Deduct Product Imports	3	1	16	34	16	16
Add Product Exports	14	211	1	90	35	35
Net Product Transfers Out/(In)	20	(2)	-	(6)	(8)	(8)
Losses, Industry Use and Other Adjustments	41	(119)	66	58	47	56
Deduct Gas Plant Butanes Supplied to Refineries	18	17	22	12	28	28
Total Requirements	1093	1055	1124	1222	1131	1339
Canada						
Total Market Product Sales	1812	1754	1933	1897	1945	2335
Deduct Product Imports	3	1	51	57	24	24
Add Product Exports	14	213	16	134	51	51
Losses, Industry Use and Other Adjustments	94	(69)	117	118	105	126
Deduct Gas Plant Butanes Supplied to Refineries	18	17	22	12	28	28
Total Requirements	1899	1880	1993	2080	2049	2460

1990 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

Comparison of Forecasts

Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	794	810	866	800	864	1165
Deduct Product Imports	-	-	51	23	7	7
Add Product Exports	-	2	44	44	16	16
Net Product Transfers Out/(In)	(19)	-	-	6	7	7
Losses, Industry Use and Other Adjustments	53	51	54	62	59	79
Deduct Gas Plant Butanes Supplied to Refineries	-	-	-	-	-	-
Total Requirements	828	863	913	889	939	1260
West of the Ottawa Valley Line						
Total Market Product Sales	1089	1035	1171	1185	1188	1516
Deduct Product Imports	11	2	77	34	18	18
Add Product Exports	14	102	16	90	32	32
Net Product Transfers Out/(In)	19	-	-	(6)	(7)	(7)
Losses, Industry Use and Other Adjustments	40	(33)	70	60	51	66
Deduct Gas Plant Butanes Supplied to Refineries	17	17	22	10	28	28
Total Requirements	1134	1085	1158	1285	1218	1561
Canada						
Total Market Product Sales	1883	1845	2037	1985	2052	2681
Deduct Product Imports	11	2	128	57	25	25
Add Product Exports	14	104	60	134	48	48
Losses, Industry Use and Other Adjustments	93	18	124	122	110	145
Deduct Gas Plant Butanes Supplied to Refineries	17	17	22	10	28	28
Total Requirements	1962	1948	2071	2174	2157	2821

1995 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

Comparison of Forecasts

Mb/d

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	827	845	930	830	921	1301
Deduct Product Imports	-	-	90	23	7	7
Add Product Exports	-	-	84	44	13	13
Net Product Transfers Out/(In)	(20)	(2)	-	6	6	6
Losses, Industry Use and Other Adjustments	53	50	59	63	63	89
Deduct Gas Plant Butanes Supplied to Refineries	-	-	-	-	-	-
Total Requirements	860	893	983	920	996	1402
West of the Ottawa Valley Line						
Total Market Product Sales	1158	1167	1290	1239	1269	1727
Deduct Product Imports	23	3	121	34	20	20
Add Product Exports	14	68	47	90	32	32
Net Product Transfers Out/(In)	20	2	-	(6)	(6)	(6)
Losses, Industry Use and Other Adjustments	43	(47)	75	63	54	74
Deduct Gas Plant Butanes Supplied to Refineries	17	17	22	10	28	28
Total Requirements	1195	1170	1269	1342	1301	1779
Canada						
Total Market Product Sales	1985	1962	2220	2069	2190	3028
Deduct Product Imports	23	3	211	57	27	27
Add Product Exports	14	68	131	134	45	45
Losses, Industry Use and Other Adjustments	96	53	134	126	117	163
Deduct Gas Plant Butanes Supplied to Refineries	17	17	22	10	28	28
Total Requirements	2055	2063	2252	2262	2297	3181

MONTREAL[1] AND WOV REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT HYDROCARBONS

NEB Forecast

Mb/d

	Light Crude Oil	Pentanes Plus	Synthetic Crude Oil	Total Light Crude and Equivalent	Heavy Crude Oil	Total
1978	997	65	70	1,132	113	1,245
1979	941	65	135	1,141	122	1,263
1980	947	65	145	1,157	126	1,283
1985	855	105	270	1,230	151	1,381
1990	622	105	565	1,292	176	1,468
1995	474	105	770	1,349	202	1,551

(1) Based on shipments of 250 Mb/d to Montreal.

MONTREAL[1] & WOV REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT HYDROCARBONS

NEB Forecast

Mb/d

	Light Crude Oil	Pentanes Plus	Synthetic Crude Oil	Total Light Crude and Equivalent	Heavy Crude Oil	Total
1978	997	65	70	1,132	113	1,245
1979	1,031	65	135	1,231	132	1,363
1980	1,037	65	145	1,247	136	1,383
1985	943	105	270	1,318	163	1,481
1990	708	105	565	1,378	190	1,568
1995	558	105	770	1,433	218	1,651

(1) Based on shipments of 350 Mb/d to Montreal

MONTREAL REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT HYDROCARBONS

NEB Forecast - 250 Mb/d Case

	Light Crude Oil	Pentanes Plus	Synthetic Crude Oil	Total Light Crude and Equivalent	Heavy Crude Oil	Other	Total
1978	197	8	15	220	30	-	250
1979	170	5	35	210	40	-	250
1980	167	8	35	210	40	-	250
1985	126	8	70	204	46	-	250
1990	49	8	140	197	53	-	250
1995	-	8	182	190	60	-	250

MONTREAL REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT HYDROCARBONS

NEB Forecast - 350 Mb/d Case

	Light Crude Oil	Pentanes Plus	Synthetic Crude Oil	Total Light Crude and Equivalent	Heavy Crude Oil	Other	Total
1978	197	8	15	220	30	-	250
1979	265	5	35	305	45	-	350
1980	262	8	35	305	45	-	350
1985	220	8	70	298	52	-	350
1990	142	8	140	290	60	-	350
1995	84	8	190	282	68	-	350

WOV REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT HYDROCARBONS

NEB Forecast

Mb/d

	Light Crude Oil	Pentanes Plus	Synthetic Crude Oil(1)	Total Light Crude and Equivalent	Heavy Crude Oil	Total
1978	800	57	55	912	83	995
1979	766	60	100	926	87	1,013
1980	775	57	110	942	91	1,033
1985	723	97	200	1,020	111	1,131
1990	566	97	425	1,088	130	1,218
1995	474	97	580	1,151	150	1,301

(1) Includes synthetic crude oil sold directly as diesel fuel.

REQUIREMENTS FOR INDIGENOUS HEAVY CRUDE OIL

NEB Forecast

Mb/d

Year	WOV Requirements for Asphalt-Yielding Crude Oil	Other WOV Requirements	Total WOV	Montreal Requirements		Total Canada	
				250 Mb/d Case	350 Mb/d Case	250 Mb/d Case	350 Mb/d Case
1978	55	28	83	30	30	113	113
1979	59	28	87	35	45	122	132
1980	63	28	91	35	45	126	136
1985	83	28	111	40	52	151	163
1990	102	28	130	46	60	176	190
1995	122	28	150	52	68	202	218

SUPPLY AND REQUIREMENTS FOR SEGREGATED PENTANES PLUS

Comparison of Forecasts

Mb/d

	Supply		Requirements				
			NEB			Submittors[2]	
	Pentanes Plus Total Supply	Segregated Net Supply(1)	Heavy Crude Blending	Refinery & Petrochemical[2]	Total	Gulf	Shell
1978	129	98	11	65	76	72	74
1979	127	96	12	65	77	73	100
1980	124	96	13	65	78	100	109
1985	102	82	11	105	116	105	91
1990	72	60	15	105	120	80	88
1995	48	38	17	105	122	53	100

(1) Supply net of volumes blended into light crude oil streams and volumes locationally constrained to the export market.

(2) Submittors forecasts correspond to NEB refinery and petrochemical forecast.

REQUIREMENTS FOR SYNTHETIC OIL

Comparison of Forecasts

Mb/d

	1978			1979			1980		
	Montreal	WOV	Total	Montreal	WOV	Total	Montreal	WOV	Total
Gulf	25	75	100	70	85	155	83	77	160
Imperial	10	23	33	20	94	114	16	99	115
Shell(1)	15	65	80	30	120	150	32	143	175
NEB(2)	15	55	70	35	100	135	35	110	145

	1985			1990			1995		
	Montreal	WOV	Total	Montreal	WOV	Total	Montreal	WOV	Total
Gulf	150	170	320	159	396	555	185	425	610
Imperial	36	155	191	70	305	375	70	375	445
Shell(1)	-	190	190	36	554	590	116	839	955
NEB(2)	70	200	270	140	425	565	190	580	770

s

(1) includes Syncrude, Cold Lake and Bitumen; excludes GCOS

(2) includes supply from upgraded heavy crude oil but excludes that from in situ pilots.

ESTABLISHED RESERVES OF CONVENTIONAL CRUDE OIL

NEB Estimates

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
NORTHWEST TERRITORIES			
1. Norman Wells			
Norman Wells	9.5	3.5	6.0
Total	**9.5**	**3.5**	**6.0**
BRITISH COLUMBIA			
1. Blueberry - Taylor Pipelines			
Aitken Creek - Gething	1.0	0.8	0.2
Blueberry - Debolt	2.1	1.7	0.4
Eagle Belloy (85%)	2.1	0.1	2.0
Inga - Inga	5.7	4.0	1.8
Other	0.3	0.2	0.1
Total	**11.3**	**6.8**	**4.5**
2. Trans-Prairie Pipelines Ltd.: Beatton River - Taylor			
Beatton River - Halfway	1.5	1.1	0.4
Beatton River West - Bluesky Gething	0.7	0.5	0.3
Eagle Belloy (15%)	0.4	0.0	0.3
Milligan Creek - Halfway	6.4	5.9	0.4
Peejay - Halfway	9.0	8.0	1.0
Weasel - Halfway	2.8	2.0	0.8
Wildmint - Halfway	1.3	1.1	0.1
Other	1.5	1.2	0.3
Total	**23.5**	**19.8**	**3.7**
3. Trans-Prairie Pipelines Ltd.: Boundary Lake - Taylor			
Boundary Lake Unit No. 1	18.6	9.4	9.2
Boundary Lake Unit No. 2	11.8	7.4	4.4
Other	3.4	2.4	0.9
Total	**33.7**	**19.2**	**14.5**

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
4. Trucked Oil (B.C. Total)			
Trucked Oil	0.9	0.4	0.5
Total	**0.9**	**0.4**	**0.5**
BRITISH COLUMBIA TOTAL	**69.5**	**46.3**	**23.2**

ALBERTA

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
1. Bow River Pipe Lines Ltd.: Light & Medium			
Provost - Viking CAK	9.2	4.4	4.8
Other	1.7	0.3	1.4
Total	**10.8**	**4.7**	**6.2**
2. Bow River Pipe Lines Ltd.: Heavy			
Bantry - Mannville A	6.5	3.8	2.7
Countess - Upper Mannville B	1.1	0.6	0.5
Countess - Upper Mannville D	4.4	2.2	2.2
Countess - Upper Mannville H	2.5	1.1	1.4
Countess - Upper Mannville O	1.2	0.2	1.0
Grand Forks - Upper Mannville B	1.1	0.2	0.9
Grand Forks - Lower Mannville D	5.4	1.1	4.3
Grand Forks - Lower Mannville K	1.2	0.3	0.9
Hays - Lower Mannville A	1.5	0.9	0.6
Lathom - Upper Mannville A	1.8	0.8	1.0
Taber - Mannville D	2.1	1.1	1.0
Taber South - Mannville B	1.8	1.5	0.3
Other	13.3	6.0	7.3
Total	**43.9**	**19.8**	**24.1**

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
3. BP Exploration Canada Limited			
Chauvin - Mannville A	1.2	0.8	0.4
Chauvin South - Sparky A&B	1.8	0.7	1.1
Chauvin South - Sparky E	0.4	0.2	0.2
Chauvin South - Sparky H	0.6	0.1	0.5
Chauvin South - Lloydminster D	0.3	0.2	0.1
Other	1.1	0.4	0.7
Total	**5.4**	**2.3**	**3.1**
4. Cremona Pipeline			
Crossfield - Cardium A	2.8	2.5	0.3
Harmattan East - Rundle	12.8	7.5	5.3
Harmattan Elkton - Rundle C	9.2	6.4	2.8
Other	5.2	3.7	1.5
Total	**30.2**	**20.2**	**10.0**
5. Federated Pipe Lines Ltd.			
Carson Creek North - BHL A	6.4	2.7	3.7
Carson Creek North - BHL B	19.7	9.3	10.4
Judy Creek - BHL A	62.0	32.3	29.7
Judy Creek - BHL B	19.9	10.5	9.3
Swan Hills - BHL A&B	123.6	60.3	63.3
Swan Hills - BHL C	30.2	12.8	17.4
Swan Hills South - BHL A&B	72.0	33.6	38.4
Virginia Hills - BHL	24.6	15.0	9.6
Other	4.8	1.9	3.0
Total	**363.2**	**178.3**	**184.9**
6. Gibson Petroleum Company Limited			
Bellshill Lake - Blairmore	7.9	4.5	3.4
Thompson Lake - Blairmore	0.7	0.4	0.2
Total	**8.6**	**4.9**	**3.6**

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
7. Gulf Alberta Pipe Line			
Clive - D-2A	3.4	1.2	2.2
Clive - D-3A	6.9	2.8	4.1
Drumheller - D-2B	1.6	0.7	1.0
Duhamel - D-2A	0.9	0.8	0.1
Duhamel - D-3B	1.2	0.9	0.3
Erskine - D-3	3.8	3.1	0.8
Fenn Big Valley - D-2A	38.0	26.3	11.7
Hussar - Glauconitic A	3.3	2.0	1.3
Joffre - D-2	11.2	5.4	5.8
Stettler - D-2A	4.0	3.5	0.5
Stettler - D-3A	3.7	2.3	1.4
West Drumheller - D-2A	4.7	3.6	1.2
Other	25.8	18.4	7.4
Total	**108.6**	**70.8**	**37.8**
8. Husky Pipeline Ltd. & Manito Pipelines Ltd.			
Lloydminster - Sparky C and GP A	1.4	0.8	0.6
Lloydminster - Sparky and GP C	3.6	1.9	1.7
Viking Kinsella - Wainwright B	4.4	0.6	3.8
Wainwright - Wainwright & Sparky A	10.0	5.8	4.2
Wildmere - Lloydminster A & Sparky B	2.4	0.4	2.0
Other	3.8	1.6	2.2
Total	**25.6**	**11.2**	**14.4**
9. The Imperial Pipe Line Company, Limited: Ellerslie			
Acheson - D-3A	17.1	11.4	5.8
Golden Spike - D-3A	33.4	24.6	8.8
Other	9.6	5.9	3.7
Total	**60.1**	**41.9**	**18.2**
10. The Imperial Pipe Line Company. Limited: Excelsior			
Excelsior - D-2	3.9	3.2	0.7
Fairydell Bon Accord - D-3A	1.8	1.3	0.5
Other	0.7	0.6	0.2
Total	**6.5**	**5.1**	**1.4**

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
11. The Imperial Pipe Line Company, Limited: Leduc			
Leduc Woodbend - D-2A	14.1	13.6	0.5
Leduc Woodbend - D-3A	38.7	35.4	3.3
Other	6.7	6.0	0.7
Total	**59.5**	**55.0**	**4.5**
12. The Imperial Pipe Line Company, Limited: Redwater			
Redwater - D-3	126.7	99.2	27.5
Total	**126.7**	**99.2**	**27.5**
13. Murphy Milk River Pipe Line			
Coutts - Total	0.7	0.2	0.5
Manyberries - Total	0.7	0.3	0.5
Other	1.7	1.3	0.5
Total	**3.2**	**1.7**	**1.4**
14. Norcen Energy Resources Ltd.			
Joarcam - Viking	15.0	13.0	2.0
Total	**15.0**	**13.0**	**2.0**
15. Peace River Oil Pipe Line Co. Ltd.			
Goose River - BHL	7.8	3.3	4.5
Kaybob - BHL A	18.1	10.6	7.5
Kaybob South - Triassic A	13.9	5.8	8.1
Nipisi - Gilwood A(39%)	18.6	8.2	10.4
Simonette - D-3	9.2	4.3	4.9
Snipe Lake - BHL	12.4	5.9	6.5
Sturgeon Lake - D-3	3.6	2.5	1.1
Sturgeon Lake South - D-3	24.9	13.1	11.9
Utikuma - KR SAND A (16%)	0.9	0.3	0.6
Other	22.7	8.8	14.0
Total	**132.2**	**62.8**	**69.4**

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
16. Pembina Pipe Line Ltd.			
Pembina - Cardium	217.3	135.4	81.9
Pembina - Keystone Belly River B	9.6	3.6	5.9
Willesden Green - Cardium A(70%)	23.3	7.6	15.7
Other	21.3	6.9	14.4
Total	**271.5**	**153.5**	**118.0**
17. Rainbow Pipe Line Company, Ltd.			
Mitsue - Gilwood A	54.2	23.8	30.4
Nipisi - Gilwood A(61%)	29.1	12.9	16.2
Rainbow - KR A	11.3	5.1	6.2
Rainbow - KR B	27.3	12.2	15.1
I.S. No. 1 Other	12.9	5.3	7.6
Rainbow - KR F	17.8	7.9	9.9
Rainbow - KR AA	12.4	4.3	8.1
I.S. No. 11 Other	2.9	2.0	0.9
I.S. No. 2 Total	4.4	1.7	2.7
Rainbow Other	12.2	5.1	7.1
Rainbow South - KR A	3.1	1.3	1.8
Rainbow South - KR B	5.2	1.8	3.4
Rainbow South - KR E	4.0	1.5	2.5
Utikuma Keg River A(84%)	4.7	1.5	3.1
Virgo - Total	5.7	4.3	1.4
Zama - Total	11.5	7.9	3.6
Other	11.8	4.0	7.8
Total	**230.4**	**102.6**	**127.8**

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
18. Rangeland Pipeline Company Limited			
Ferrier - Cardium D	1.9	0.8	1.1
Ferrier - Cardium E	4.8	1.0	3.8
Gilby - Jurassic B	3.7	1.5	2.1
Gilby - Mannville B	2.4	0.7	1.7
Gilby - Viking A	2.6	2.3	0.3
Innisfail - D-3	11.8	7.8	4.1
Medicine River - Glauconitic A	2.2	0.8	1.4
Medicine River - Jurassic A	1.8	1.1	0.7
Medicine River - Jurassic D	2.1	0.9	1.2
Sundre - Rundle A	5.1	3.6	1.5
Willesden Green - Cardium A(30%)	10.0	3.3	6.7
Other	28.4	11.5	17.0
Total	**76.8**	**35.2**	**41.7**
19. Texaco Exploration Canada Ltd.			
Bonnie Glen - D-3A	73.1	45.0	28.2
Glen Park - D-3A	3.4	2.0	1.3
Westerose - D-3	21.2	10.7	10.5
Wizard Lake - D-3A	51.3	29.8	21.5
Other	1.6	1.5	0.2
Total	**150.7**	**89.0**	**61.7**
20. Trans-Prairie Pipelines Ltd.: Boundary Lake South			
Boundary Lake South - Triassic C	0.7	0.2	0.5
Boundary Lake South - Triassic E	3.8	1.1	2.7
Other	0.3	0.0	0.2
Total	**4.7**	**1.3**	**3.4**
21. Twining Pipeline Division			
Twining - Rundle A and LM A	3.6	1.2	2.3
Twining North - Rundle	1.2	0.3	0.9
Other	0.6	0.1	0.4
Total	**5.4**	**1.7**	**3.6**

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
22. Valley Pipe Line			
Turner Valley - Rundle & Shallow	22.5	20.3	2.1
Total	**22.5**	**20.3**	**2.1**
23. Truck and Tank Car (Light)			
Total	**0.8**	**0.6**	**0.2**
24. Truck and Tank Car (Heavy)			
Cessford - Total	4.6	2.7	1.9
Other	3.8	1.9	2.0
Total	**8.4**	**4.6**	**3.8**
25. Undefined and Confidential			
Light	6.6	1.3	5.3
Heavy	1.2	0.3	0.9
Total	**7.8**	**1.6**	**6.2**
ALBERTA TOTAL	**1 778.3**	**1 001.5**	**776.8**

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
SASKATCHEWAN			
1. Husky Pipeline Ltd. & Manito Pipelines Ltd.			
Aberfeldy - Sparky, Aberfeldy Unit	5.2	3.6	1.6
South Aberfeldy - Sparky, Voluntary Unit	1.7	1.1	0.6
Dulwich - Sparky	1.9	1.4	0.5
Epping - Sparky and G.P., Non-Unit	2.1	1.4	0.7
South Epping - Sparky and G.P., Unit No. 1	2.9	1.9	1.0
S.W. Epping Sparky Vol. Unit No. 1	1.0	0.5	0.5
Furness - Sparky	0.4	0.2	0.1
Golden Lake North - Waseca & Sparky, Vol. Unit	1.8	1.0	0.8
Golden Lake North - Waseca & Sparky, Non-Unit	0.4	0.2	0.2
Golden Lake South - Sparky	0.6	0.2	0.3
Golden Lake South - Waseca	1.5	0.7	0.9
Gully Lake - Waseca, Vol. Unit No. 1	0.9	0.4	0.5
Gully Lake - Waseca, Non-Unit	0.6	0.2	0.3
Lashburn - Waseca, Vol. Unit	0.8	0.6	0.2
Lone Rock - Sparky	1.2	1.1	0.1
Tangleflags (Total)	2.5	0.7	1.8
Other	7.2	3.9	3.3
Total	**32.7**	**19.1**	**13.6**
2. Bow River Pipe Lines Ltd. (Heavy Blend)			
Coleville - Bakken	7.4	4.9	2.4
Dodsland - Viking, Eagle Lake, Vol. Unit	2.4	1.4	1.0
Dodsland - Viking, Gleneath Unit	2.3	1.3	1.0
Eureka - Viking, South Unit	1.5	0.8	0.7
North Hoosier - Bakken, Vol. Unit	1.0	0.5	0.5
North Hoosier - Basal Blairmore, Vol. Unit	0.6	0.4	0.2
Smiley Dewar - Viking	5.2	3.5	1.7
Other	4.4	2.9	1.5
Total	**24.7**	**15.7**	**9.0**

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
3. South Saskatchewan Pipe Line Company			
Battrum - Roseray, Unit No. 1	5.7	3.7	2.1
Cantuar Main - Cantuar, Unit	4.0	2.9	1.0
Dollard - Upper Shaunavon, Unit	13.6	11.2	2.4
Fosterton - Roseray, Main Unit	10.2	7.8	2.4
Gull Lake North - Upper Shaunavon, Unit	3.1	2.6	0.5
Instow - Upper Shaunavon, Unit	8.1	6.2	1.9
Main Success - Roseray, Unit	2.7	2.4	0.3
North Premier - Roseray, Unit No. 3	2.1	1.8	0.3
Rapdan - Upper Shaunavon, Unit	3.1	1.9	1.2
South Success - Roseray, Unit	3.7	2.9	0.8
Suffield - Upper Shaunavon, Unit No. 2	0.8	0.4	0.4
Verlo - Roseray, Unit	1.9	0.8	1.1
Other	28.7	18.7	10.1
Total	**87.8**	**63.3**	**24.4**
4. Westspur Pipe Line Company - S.E. Saskatchewan Medium			
Benson - Midale, Unit	1.7	1.1	0.6
Innes - Frobisher	2.1	1.4	0.7
Lost Horse Hill - Frobisher Alida, Vol. Unit No. 1	2.0	1.5	0.4
Midale - Central Midale, Unit	17.4	12.6	4.8
Midale - Central Midale, Non-Unit	1.3	0.7	0.6
Viewfield - Frobisher	1.4	0.5	0.9
Weyburn - Midale, Unit	52.8	35.3	17.5
Weyburn - Midale, Non-Unit	1.1	0.7	0.4
Other	14.8	9.6	5.2
Total	**94.5**	**63.4**	**31.1**
5. Westspur - Medium Pipe Line - Batched Light			
Flat Lake - Ratcliffe, Vol. Unit No. 1	1.9	1.0	0.9
Freda Lake - Ratcliffe	0.5	0.3	0.2
Sherwood - Frobisher	1.8	1.4	0.4
Skinner Lake - Ratcliffe	0.3	0.1	0.2
Total	**4.5**	**2.7**	**1.7**

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
6. Westspur Pipe Line Company - S.E. Saskatchewan Light			
Alida East - Alida, Unit	1.9	1.6	0.3
Carnduff - Midale, East Unit	2.7	2.4	0.3
Elmore - Frobisher Vol. Unit	2.2	1.3	0.9
Ingoldsby - Frobisher Alida, Vol. Unit	2.7	1.9	0.8
Kenosee - Tilston, Vol. Unit	2.0	1.3	0.7
Parkman - Tilston Souris Valley	3.0	2.4	0.6
Queensdale East-Frobisher Alida, Non-Unit	4.6	3.2	1.5
Rosebank - Frobisher Alida, Vol. Unit No. 1	3.6	3.2	0.4
Steelman - Midale, Unit 1A	9.6	7.2	2.4
Steelman - Midale, Unit II	8.4	6.8	1.6
Steelman - Midale, Unit III	4.2	3.4	0.8
Steelman - Midale, Unit IV	5.3	3.8	1.5
Steelman - Midale, Unit VI	9.2	8.0	1.3
Willmar - Frobisher Alida, Non-Unit	3.0	2.2	0.9
Workamn - Forbisher, Vol. Unit No. 1	1.7	1.4	0.3
Other	43.2	32.7	10.5
Total	**107.6**	**82.7**	**24.9**
SASKATCHEWAN TOTAL	**351.7**	**246.9**	**104.8**

MANITOBA

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
1. Trans-Prairie Pipelines Ltd.			
Daly - Mississippian	3.5	2.9	0.7
North Virden Scallion - Mississippian	11.2	7.8	3.4
Routledge - Mississippian	2.4	2.0	0.3
Virden Roselea - Mississippian	7.5	5.0	2.5
Other	1.5	1.1	0.3
Total	**26.0**	**18.8**	**7.2**
MANITOBA TOTAL	**26.0**	**18.8**	**7.2**

	Initial Recoverable Reserves	Cumulative Production to 1/1/78 (Million cubic metres)	Remaining Reserves at 1/1/78
ONTARIO			
1. Ontario			
ONTARIO TOTAL	**9.7**	**8.7**	**1.0**
CANADA - TOTAL*	**2 244.7**	**1 325.8**	**918.9**

*Frontier reserves not included.

POTENTIAL PRODUCIBILITY FROM ESTABLISHED CRUDE OIL RESERVES

NEB Forecast m^3/d

LIGHT CRUDE OIL

NORTHWEST TERRITORIES

Norman Wells

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Pipeline Total	**477**	**477**	**477**	**477**	**477**	**477**	**477**	**477**	**477**	**477**	**477**	**477**	**477**	**477**	**477**	**477**	**477**	**477**

BRITISH COLUMBIA

Blueberry - Taylor Pipelines

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Aitken Creek - Gething	119	98	82	68	56	46	38	32	26	22	18	3	0	0	0	0	0	0
Blueberry - Debolt	125	108	94	83	74	66	59	54	49	44	41	37	34	32	30	27	26	24
Eagle Belloy (85%)	321	422	473	471	432	383	340	302	267	237	210	187	166	147	130	115	102	91
Inga - Inga	626	550	483	424	372	327	287	252	221	194	171	150	132	116	102	89	78	69
Other	47	44	39	35	31	27	24	21	19	17	15	13	11	10	9	8	7	6
Pipeline Total	**1 238**	**1 223**	**1 171**	**1 080**	**965**	**850**	**749**	**660**	**583**	**515**	**455**	**390**	**343**	**304**	**270**	**240**	**213**	**190**

Trans-Prairie Pipelines Ltd.: Beatton River - Taylor

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Beatton River - Halfway	139	127	113	101	90	80	72	64	57	51	45	40	36	32	29	25	23	20
Beatton River West - Bluesky Gething	130	118	100	80	65	52	41	33	27	21	17	12	0	0	0	0	0	0
Eagle Belloy (15%)	57	74	83	83	77	68	60	54	48	42	37	33	29	26	23	20	18	16
Milligan Creek - Halfway	220	187	159	135	115	97	83	70	60	51	43	0	0	0	0	0	0	0
Peejay - Halfway	570	483	379	297	233	183	143	112	88	69	54	0	0	0	0	0	0	0
Weasel - Halfway	365	333	290	240	199	165	137	113	94	78	64	53	44	37	8	0	0	0
Wildmint - Halfway	78	62	49	39	31	25	20	16	13	10	4	0	0	0	0	0	0	0
Other	160	135	113	96	80	68	57	48	40	29	0	0	0	0	0	0	0	0
Pipeline Total	**1 719**	**1 520**	**1 288**	**1 072**	**890**	**738**	**613**	**510**	**426**	**351**	**266**	**139**	**110**	**95**	**59**	**46**	**41**	**36**

Trans-Prairie Pipelines Ltd.: Boundary Lake - Taylor

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Boundary Lake Unit No. 1	1 565	1 519	1 450	1 361	1 277	1 198	1 125	1 055	990	929	872	819	768	721	677	635	596	559
Boundary Lake Unit No. 2	1 066	978	898	823	756	693	636	584	536	492	451	414	380	349	320	294	269	247
Other	294	280	255	223	195	170	148	129	113	99	86	75	65	57	50	44	38	33
Pipeline Total	**2 926**	**2 777**	**2 603**	**2 407**	**2 227**	**2 062**	**1 909**	**1 769**	**1 639**	**1 520**	**1 410**	**1 308**	**1 214**	**1 127**	**1 046**	**972**	**903**	**840**

LIGHT CRUDE OIL

Trucked Oil (B.C. TOTAL)

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Trucked Oil	131	121	110	100	91	83	76	69	63	57	52	47	43	39	35	32	29	27
British Columbia Total	**6 014**	**5 642**	**5 173**	**4 661**	**4 174**	**3 733**	**3 347**	**3 009**	**2 711**	**2 443**	**2 182**	**1 885**	**1 710**	**1 565**	**1 412**	**1 291**	**1 187**	**1 093**

ALBERTA

Bow River Pipe Lines Ltd.: Light & Medium

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Provost - Viking CAK	1 260	1 137	1 027	929	840	761	690	627	569	518	471	429	391	357	326	298	273	249
Other	119	117	116	115	113	109	106	102	99	96	93	90	88	85	82	80	77	75
Pipeline Total	**1 379**	**1 255**	**1 143**	**1 044**	**953**	**871**	**796**	**729**	**669**	**614**	**565**	**520**	**479**	**442**	**409**	**378**	**350**	**325**

Cremona Pipeline

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Crossfield - Cardium A	127	111	98	86	75	66	58	51	45	39	34	30	5	0	0	0	0	0
Harmattan East - Rundle	1 756	1 621	1 439	1 231	1 058	914	792	690	603	528	465	410	363	322	287	256	229	206
Harmattan Elkton - Rundle C	994	873	767	673	591	519	456	400	352	309	271	238	209	184	161	141	124	109
Other	525	468	417	372	331	295	263	234	209	186	166	148	132	117	105	93	74	0
Pipeline Total	**3 402**	**3 074**	**2 721**	**2 363**	**2 057**	**1 795**	**1 570**	**1 376**	**1 208**	**1 063**	**936**	**826**	**709**	**623**	**553**	**491**	**427**	**315**

Federated Pipe Lines Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Carson Creek North - BHL A	899	855	813	755	685	621	562	510	462	419	379	344	312	283	256	232	210	191
Carson Creek North - BHL B	2 974	2 886	2 677	2 371	2 100	1 859	1 647	1 458	1 291	1 144	1 013	897	794	703	623	551	488	432
Judy Creek - BHL A	11 471	9 883	8 514	7 335	6 319	5 444	4 690	4 041	3 481	2 999	2 584	2 226	1 918	1 652	1 423	1 226	1 056	910
Judy Creek - BHL B	3 552	3 075	2 663	2 306	1 997	1 729	1 497	1 296	1 122	972	841	728	631	546	473	410	355	307
Swan Hills - BHL A&B	12 385	11 664	10 913	10 141	9 424	8 758	8 138	7 563	7 028	6 531	6 070	5 640	5 242	4 871	4 527	4 207	3 909	3 633
Swan Hills - BHL C	2 325	2 212	2 080	1 938	1 809	1 693	1 588	1 492	1 405	1 325	1 252	1 185	1 123	1 065	1 012	963	918	875
Swan Hills South - BHL A&B	10 305	10 101	9 455	8 442	7 538	6 731	6 010	5 366	4 792	4 278	3 820	3 411	3 046	2 720	2 428	2 168	1 936	1 729
Virginia Hills - BHL	2 149	2 003	1 856	1 707	1 571	1 445	1 330	1 224	1 126	1 036	953	877	807	743	683	629	578	532
Other	916	889	862	789	680	586	505	435	374	323	278	239	206	178	153	132	113	98
Pipeline Total	**46 976**	**43 569**	**39 834**	**35 785**	**32 123**	**28 866**	**25 968**	**23 386**	**21 083**	**19 027**	**17 191**	**15 549**	**14 078**	**12 761**	**11 579**	**10 518**	**9 565**	**8 707**

LIGHT CRUDE OIL

Gibson Petroleum Company Limited

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Bellshill Lake - Blairmore	996	898	809	729	657	592	533	481	433	390	352	317	286	257	232	209	188	170
Thompson Lake - Blairmore	67	64	60	54	49	44	40	36	32	29	26	24	21	19	17	16	14	13
Pipeline Total	**1 063**	**962**	**869**	**783**	**706**	**636**	**573**	**517**	**466**	**420**	**378**	**341**	**307**	**277**	**249**	**225**	**203**	**183**

Gulf Alberta Pipe Line

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Clive - D-2A	424	387	354	325	299	276	255	236	220	205	191	178	167	157	147	138	130	123
Clive - D-3A	938	938	938	937	876	777	689	611	542	481	426	378	335	297	264	234	208	184
Drumheller - D-2B	254	239	217	196	177	160	145	131	119	108	97	88	80	72	65	59	53	48
Duhamel - D-2A	70	55	43	34	26	20	12	0	0	0	0	0	0	0	0	0	0	0
Duhamel - D-3B	114	98	85	73	63	54	46	40	34	30	25	22	19	16	14	7	0	0
Erskine - D-3	190	174	160	148	138	128	120	113	107	101	95	91	86	82	79	75	72	69
Fenn Big Valley - D-2A	6 008	5 359	4 289	3 432	2 747	2 198	1 759	1 408	1 127	902	722	577	462	370	296	237	189	46
Hussar - Glauconitic A	395	376	345	306	272	241	214	190	168	149	132	117	104	92	82	73	64	57
Joffre - D-2	620	652	667	667	667	652	601	555	514	479	448	420	396	373	353	335	318	303
Stettler - D-2A	201	192	172	145	123	104	87	74	62	53	44	38	32	22	0	0	0	0
Stettler - D-3A	335	308	283	260	239	219	202	185	170	157	144	132	121	112	102	94	86	79
West Drumheller - D-2A	432	380	335	294	259	228	200	176	155	136	120	106	93	82	72	63	55	34
Other	1 800	1 747	1 641	1 492	1 356	1 233	1 120	1 018	926	841	765	695	632	574	522	475	431	392
Pipeline Total	**11 784**	**10 905**	**9 529**	**8 311**	**7 242**	**6 292**	**5 453**	**4 739**	**4 145**	**3 640**	**3 211**	**2 843**	**2 527**	**2 250**	**1 997**	**1 790**	**1 609**	**1 338**

The Imperial Pipe Line Company, Limited: Ellerslie

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Acheson - D-3A	2 543	2 543	2 395	1 888	1 470	1 145	892	694	541	421	328	255	199	155	121	94	73	3
Golden Spike - D-3A	4 590	3 726	3 024	2 455	1 993	1 618	1 313	1 066	865	702	570	463	376	305	247	201	163	132
Other	1 080	1 017	957	875	775	686	608	539	477	422	374	331	294	260	230	204	181	160
Pipeline Total	**8 212**	**7 285**	**6 377**	**5 218**	**4 238**	**3 449**	**2 813**	**2 299**	**1 883**	**1 546**	**1 272**	**1 050**	**868**	**720**	**598**	**499**	**417**	**296**

The Imperial Pipe Line Company, Limited: Excelsior

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Excelsior - D-2	443	362	281	218	169	131	101	78	61	47	36	28	4	0	0	0	0	0
Fairydell Bon Accord - D-3A	193	167	145	126	109	95	82	72	62	54	47	41	35	31	27	23	20	17
Other	57	50	45	40	35	31	27	24	22	19	17	15	13	12	10	9	7	0
Pipeline Total	**692**	**580**	**471**	**383**	**313**	**257**	**211**	**174**	**145**	**120**	**100**	**84**	**53**	**42**	**37**	**32**	**27**	**17**

LIGHT CRUDE OIL

The Imperial Pipe Line Company, Limited: Leduc

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Leduc Woodbend - D-2A	157	169	175	172	148	123	103	86	72	60	50	42	35	1	0	0	0	0
Leduc Woodbend - D-3A	1 724	1 403	1 143	930	758	617	502	409	333	271	221	180	146	119	97	79	37	0
Other	211	189	169	151	135	121	109	97	87	78	70	62	56	50	45	40	36	32
Pipeline Total	**2 091**	**1 761**	**1 486**	**1 253**	**1 041**	**861**	**714**	**592**	**492**	**409**	**341**	**284**	**237**	**170**	**142**	**119**	**73**	**32**

The Imperial Pipe Line Company, Limited: Redwater

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Redwater - D-3	15 999	12 642	9 989	7 893	6 237	4 928	3 894	3 077	2 431	1 921	1 518	1 199	948	749	592	468	369	292
Pipeline Total	**15 999**	**12 642**	**9 989**	**7 893**	**6 237**	**4 928**	**3 894**	**3 077**	**2 431**	**1 921**	**1 518**	**1 199**	**948**	**749**	**592**	**468**	**369**	**292**

Murphy Milk River Pipe Line

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Coutts - Total	162	162	152	130	111	94	80	68	58	50	42	36	31	26	22	19	16	14
Manyberries - Total	77	73	69	65	62	58	55	52	50	47	44	42	40	38	36	34	32	30
Other	159	151	132	115	99	87	75	65	57	49	43	37	32	28	24	21	18	16
Pipeline Total	**398**	**386**	**353**	**310**	**272**	**239**	**211**	**186**	**165**	**146**	**130**	**116**	**103**	**92**	**82**	**74**	**67**	**60**

Norcen Energy Resources Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Joarcam - Viking	877	794	692	580	487	408	342	287	241	202	169	142	119	59	0	0	0	0
Pipeline Total	**877**	**794**	**692**	**580**	**487**	**408**	**342**	**287**	**241**	**202**	**169**	**142**	**119**	**59**	**0**	**0**	**0**	**0**

LIGHT CRUDE OIL

Peace River Oil Pipe Line Co. Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Goose River - BHL	1 038	1 018	998	940	850	768	695	628	568	514	465	420	380	344	311	281	254	230
Kaybob - BHL A	1 762	1 727	1 693	1 596	1 445	1 308	1 185	1 073	972	880	797	721	653	592	536	485	439	398
Kaybob South - Triassic A	2 336	2 171	1 949	1 749	1 570	1 409	1 265	1 136	1 019	915	821	737	662	594	533	479	430	386
Nipisi - Gilwood A(39%)	3 766	3 619	3 268	2 767	2 343	1 984	1 680	1 422	1 204	1 020	864	731	619	524	444	376	318	270
Simonette - D-3	1 230	1 122	1 023	934	852	777	709	647	590	538	491	448	408	373	340	310	283	258
Snipe Lake - BHL	1 302	1 238	1 178	1 107	1 026	952	883	819	760	705	653	606	562	521	484	449	416	386
Sturgeon Lake - D-3	389	345	305	270	239	212	188	166	147	130	116	102	91	80	71	63	56	49
Sturgeon Lake South - D-3	3 070	2 862	2 631	2 384	2 160	1 957	1 773	1 606	1 455	1 318	1 195	1 082	981	888	805	729	661	599
Utikuma - KR SAND A	154	148	143	132	119	106	95	85	77	69	61	55	49	44	40	36	32	29
Other	2 192	2 127	2 064	2 003	1 913	1 799	1 691	1 590	1 494	1 405	1 321	1 242	1 167	1 097	1 032	970	912	857
Pipeline Total	**17 240**	**16 377**	**15 252**	**13 882**	**12 517**	**11 274**	**10 164**	**9 173**	**8 287**	**7 494**	**6 784**	**6 146**	**5 573**	**5 059**	**4 595**	**4 178**	**3 801**	**3 461**

Pembina Pipe Line Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Pembina - Cardium	10 205	9 398	8 693	8 072	7 521	7 031	6 591	6 196	5 839	5 515	5 220	4 950	4 703	4 475	4 266	4 072	3 893	3 726
Pembina - Keystone Belly River B	1 384	1 357	1 330	1 250	1 125	1 013	912	820	738	665	598	539	485	436	393	353	318	286
Willesden Green - Cardium A(70%)	1 432	1 403	1 376	1 348	1 305	1 248	1 194	1 144	1 095	1 050	1 007	966	927	891	856	823	791	761
Other	1 888	1 851	1 814	1 752	1 668	1 588	1 512	1 440	1 371	1 305	1 243	1 183	1 126	1 072	1 021	972	925	881
Pipeline Total	**14 909**	**14 009**	**13 213**	**12 422**	**11 620**	**10 880**	**10 210**	**9 600**	**9 044**	**8 535**	**8 067**	**7 638**	**7 241**	**6 875**	**6 536**	**6 221**	**5 928**	**5 656**

Rainbow Pipe Line Company, Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Mitsue - Gilwood A	8 303	7 488	6 752	6 088	5 490	4 951	4 464	4 026	3 630	3 274	2 952	2 662	2 400	2 165	1 952	1 760	1 587	1 431
Nipisi - Gilwood A(61%)	5 891	5 660	5 111	4 329	3 667	3 105	2 630	2 227	1 886	1 598	1 353	1 146	971	822	696	590	499	423
Rainbow - KR A	1 669	1 669	1 669	1 669	1 621	1 389	1 171	988	834	703	594	501	422	356	301	254	214	181
Rainbow - KR B	4 291	4 291	4 291	4 291	3 993	3 339	2 789	2 329	1 946	1 625	1 357	1 134	947	791	661	552	461	385
I.S. No. 1 Other	1 888	1 851	1 814	1 778	1 650	1 449	1 272	1 117	980	860	755	663	582	511	449	394	346	304
Rainbow - KR F	2 701	2 701	2 701	2 701	2 646	2 267	1 893	1 581	1 321	1 103	922	770	643	537	449	375	313	261
Rainbow - KR AA	2 225	2 220	2 154	2 069	1 988	1 898	1 640	1 370	1 144	956	798	667	557	465	389	324	271	226
I.S. No. 11 Other	472	406	350	283	215	164	124	94	72	55	41	31	24	18	0	0	0	0
I.S. No. 2 Total	874	874	874	809	677	567	474	397	332	278	233	195	163	136	114	96	80	67
Rainbow Other	1 744	1 735	1 726	1 718	1 606	1 410	1 238	1 087	954	837	735	645	567	497	437	383	336	295
Rainbow South - KR A	524	524	524	524	480	401	335	279	233	195	163	136	114	95	79	66	55	46
Rainbow South - KR B	969	969	969	969	921	773	646	539	451	376	314	263	219	183	153	128	107	89
Rainbow South - KR E	666	662	659	656	609	526	455	393	340	294	254	220	190	164	142	123	106	92
Utikuma Keg River A(84%)	811	779	749	695	622	557	499	447	400	358	321	287	257	230	206	184	165	148
Virgo - Total	674	563	471	393	328	274	229	191	160	133	111	93	78	65	54	45	9	0
Zama - Total	1 557	1 552	1 369	1 132	936	774	640	529	438	362	299	248	88	0	0	0	0	0
Other	1 716	1 716	1 716	1 716	1 716	1 716	1 708	1 518	1 280	1 080	911	769	649	547	462	389	328	277
Pipeline Total	**36 977**	**35 663**	**33 900**	**31 822**	**29 169**	**25 560**	**22 210**	**19 116**	**16 403**	**14 090**	**12 116**	**10 430**	**8 871**	**7 584**	**6 543**	**5 664**	**4 880**	**4 226**

LIGHT CRUDE OIL

Rangeland Pipeline Company Limited

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Ferrier - Cardium D	334	334	325	285	248	215	187	163	141	123	107	93	81	70	61	53	46	40
Ferrier - Cardium E	336	340	342	342	342	338	319	298	280	263	249	235	222	211	200	190	181	173
Gilby - Jurassic B	458	454	449	427	390	356	325	297	271	247	226	206	188	172	157	143	131	119
Gilby - Mannville B	167	183	199	207	207	206	199	189	180	171	163	155	148	140	134	127	121	115
Gilby - Viking A	92	85	78	71	64	58	52	47	42	38	34	31	28	25	23	21	19	17
Innisfail - D-3	1 832	1 565	1 307	1 092	912	762	636	531	444	371	310	259	216	180	151	126	105	88
Medicine River - Glauconitic A	253	250	248	238	222	206	192	179	167	155	144	134	125	117	109	101	94	88
Medicine River - Jurassic A	259	254	232	196	166	140	118	100	85	72	60	51	43	37	31	26	1	0
Medicine River - Jurassic D	253	243	226	210	196	182	169	158	147	137	127	118	110	102	95	89	82	77
Sundre - Rundle A	481	429	383	341	305	272	243	217	193	172	154	137	123	109	98	87	78	69
Willesden Green - Cardium A(30%)	614	601	589	578	559	535	512	490	470	450	432	414	398	382	367	353	339	327
Other	3 601	3 494	3 391	3 291	3 193	2 993	2 708	2 450	2 217	2 006	1 815	1 642	1 485	1 344	1 216	1 100	995	901
Pipeline Total	**8 679**	**8 232**	**7 769**	**7 278**	**6 803**	**6 265**	**5 662**	**5 120**	**4 637**	**4 206**	**3 821**	**3 476**	**3 168**	**2 890**	**2 641**	**2 417**	**2 194**	**2 014**

Texaco Exploration Canada Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Bonnie Glen - D-3A	16 799	15 508	12 694	9 136	6 575	4 732	3 406	2 451	1 764	1 270	914	658	473	341	245	176	91	0
Glen Park - D-3A	499	451	409	357	302	255	215	182	154	130	110	93	78	66	56	47	40	34
Westerose - D-3	3 565	3 391	3 069	2 639	2 269	1 951	1 677	1 442	1 240	1 066	917	788	678	583	501	431	370	318
Wizard Lake - D-3A	11 160	10 616	9 048	6 869	5 214	3 958	3 005	2 281	1 731	1 314	998	757	575	436	331	251	191	145
Other	44	44	43	43	42	42	38	30	24	20	16	13	10	8	7	5	4	0
Pipeline Total	**32 068**	**30 010**	**25 264**	**19 044**	**14 403**	**10 939**	**8 341**	**6 387**	**4 914**	**3 800**	**2 954**	**2 309**	**1 815**	**1 434**	**1 140**	**911**	**696**	**497**

Trans-Prairie Pipelines Ltd.: Boundary Lake South

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Boundary Lake South - Triassic C	76	76	76	74	69	64	60	56	53	49	46	43	41	38	35	33	31	29
Boundary Lake South - Triassic E	676	663	650	607	539	478	425	377	335	297	264	234	208	185	164	146	129	115
Other	60	60	60	60	60	55	47	40	34	29	25	21	18	15	13	11	9	8
Pipeline Total	**813**	**799**	**786**	**740**	**668**	**598**	**532**	**474**	**422**	**376**	**335**	**299**	**267**	**238**	**213**	**190**	**170**	**152**

LIGHT CRUDE OIL

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Twining Pipeline Division																		
Twining - Rundle A and LM A	626	608	590	535	456	391	338	294	257	226	199	177	157	141	126	114	103	93
Twining North - Rundle	211	219	218	197	176	158	142	127	114	102	91	82	73	65	59	53	47	42
Other	44	44	43	42	40	38	37	35	34	32	31	30	29	27	26	25	24	23
Pipeline Total	**881**	**870**	**851**	**775**	**673**	**588**	**517**	**456**	**404**	**360**	**321**	**288**	**259**	**234**	**211**	**192**	**174**	**159**
Valley Pipe Line																		
Turner Valley - Rundle & Shallow	522	501	473	437	404	374	345	319	295	273	253	233	216	200	185	171	158	146
Pipeline Total	**522**	**501**	**473**	**437**	**404**	**374**	**345**	**319**	**295**	**273**	**253**	**233**	**216**	**200**	**185**	**171**	**158**	**146**
Truck and Tank Car																		
Pipeline Total	**67**	**64**	**61**	**58**	**55**	**52**	**44**	**33**	**25**	**18**	**14**	**10**	**8**	**6**	**4**	**2**	**0**	**0**
Alberta Total	**205 031**	**189 739**	**171 033**	**150 383**	**131 982**	**115 134**	**100 572**	**88 041**	**77 359**	**68 263**	**60 478**	**53 785**	**47 848**	**42 707**	**38 308**	**34 540**	**31 109**	**27 876**

SASKATCHEWAN

Westspur - Medium Pipe Line - Batched Light

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Flat Lake - Ratcliffe, Vol. Unit No. 1	211	194	179	165	152	140	129	119	109	101	93	86	79	73	67	62	57	52
Freda Lake - Ratcliffe	55	50	46	42	39	36	33	30	27	25	23	21	19	18	16	15	14	13
Sherwood - Frobisher	130	117	105	94	85	76	69	62	56	50	45	41	36	33	30	27	24	21
Skinner Lake - Ratcliffe	45	43	41	38	35	32	30	27	25	23	21	20	18	17	16	14	13	12
Pipeline Total	**440**	**404**	**371**	**339**	**311**	**284**	**260**	**238**	**218**	**200**	**183**	**167**	**154**	**141**	**129**	**118**	**108**	**99**

LIGHT CRUDE OIL

Westspur Pipe Line Company - S.E. Sask. Light

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Alida East - Alida, Unit	72	67	63	59	55	51	48	45	42	39	36	34	32	30	28	26	24	22
Carnduff - Midale, East Unit	116	105	94	85	77	69	62	56	51	45	41	37	32	0	0	0	0	0
Elmore - Frobisher Vol. Unit	189	180	169	157	145	135	125	116	107	99	92	85	79	74	68	63	59	54
Ingoldsby - Frobisher Alida, Vol. Unit	145	134	125	116	108	101	95	89	84	79	75	71	67	63	60	57	55	52
Kenosee - Tilston, Vol. Unit	300	297	269	222	183	150	124	102	84	69	57	47	39	32	26	0	0	0
Parkman - Tilston Souris Valley	189	171	155	141	127	115	105	95	86	78	70	64	58	52	48	43	13	0
Queensdale East-Frobisher Alida, Non-Unit	372	340	311	284	259	237	216	198	181	165	151	138	126	115	105	96	88	80
Rosebank - Frobisher Alida, Vol. Unit No. 1	174	151	131	113	98	85	73	63	55	48	41	35	31	27	6	0	0	0
Steelman - Midale, Unit 1A	565	521	481	444	410	379	349	322	298	275	253	234	216	199	184	170	157	145
Steelman - Midale, Unit II	395	361	331	302	276	253	231	211	193	177	162	148	135	124	113	103	95	86
Steelman - Midale, Unit III	258	235	211	189	170	153	137	123	110	99	89	80	72	64	58	52	47	42
Steelman - Midale, Unit IV	448	418	384	348	316	287	260	236	214	194	176	159	144	131	119	108	98	89
Steelman - Midale, Unit VI	422	376	336	300	267	239	213	190	169	151	135	120	107	96	85	76	68	61
Willmar - Frobisher Alida, Non-Unit	243	222	203	186	170	156	142	130	119	109	100	91	83	76	70	64	58	53
Workamn - Forbisher, Vol. Unit No. 1	128	115	103	93	83	75	67	60	54	48	44	39	35	14	0	0	0	0
Other	2 870	2 676	2 495	2 289	2 067	1 866	1 684	1 520	1 372	1 239	1 118	1 009	911	823	742	670	605	546
Pipeline Total	**6 889**	**6 372**	**5 862**	**5 329**	**4 813**	**4 349**	**3 933**	**3 557**	**3 220**	**2 915**	**2 641**	**2 393**	**2 168**	**1 920**	**1 713**	**1 529**	**1 365**	**1 231**
Saskatchewan Total	**7 329**	**6 777**	**6 233**	**5 668**	**5 124**	**4 634**	**4 193**	**3 796**	**3 438**	**3 115**	**2 824**	**2 561**	**2 322**	**2 060**	**1 842**	**1 647**	**1 473**	**1 330**

MANITOBA

Trans-Prairie Pipelines Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Daly - Mississippian	192	179	164	149	135	122	110	100	90	82	74	67	61	55	50	45	41	37
North Virden Scallion - Mississippian	734	678	627	580	536	496	458	424	392	362	335	310	287	265	245	226	209	194
Routledge - Mississippian	147	137	123	106	91	79	68	58	50	43	37	18	0	0	0	0	0	0
Virden Roselea - Mississippian	425	402	379	359	339	321	303	286	271	256	242	229	216	204	193	182	172	163
Other	136	128	113	95	79	67	56	47	39	33	27	23	19	9	0	0	0	0
Pipeline Total	**1 633**	**1 524**	**1 408**	**1 289**	**1 181**	**1 083**	**995**	**915**	**842**	**776**	**715**	**646**	**582**	**533**	**488**	**454**	**423**	**393**
Manitoba Total	**1 633**	**1 524**	**1 408**	**1 289**	**1 181**	**1 083**	**995**	**915**	**842**	**776**	**715**	**646**	**582**	**533**	**488**	**454**	**423**	**393**

ONTARIO

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Ontario - Total	**243**	**223**	**204**	**187**	**171**	**156**	**143**	**131**	**120**	**110**	**101**	**92**	**84**	**77**	**71**	**65**	**59**	**54**

HEAVY CRUDE OIL

ALBERTA

Bow River Pipe Lines Ltd.: Heavy

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Bantry - Mannville A	604	575	547	510	466	426	389	355	325	297	271	248	226	207	189	173	158	144
Countess - Upper Mannville B	215	201	177	148	123	102	85	71	59	49	41	34	29	24	20	13	0	0
Countess - Upper Mannville D	1 089	1 112	970	725	543	406	304	227	170	127	95	71	53	27	0	0	0	0
Countess - Upper Mannville H	550	507	451	384	328	279	238	203	173	148	126	107	92	78	67	57	48	41
Countess - Upper Mannville O	244	224	205	188	173	159	146	134	123	113	103	95	87	80	73	67	62	57
Grand Forks - Upper Mannville B	234	218	197	178	161	146	132	119	108	97	88	80	72	65	59	53	48	43
Grand Forks - Lower Mannville D	1 478	1 524	1 381	1 174	999	849	722	614	522	444	378	321	273	232	198	168	143	121
Grand Forks - Lower Mannville K	425	382	315	260	215	177	146	120	99	82	68	56	46	38	31	26	21	17
Hays - Lower Mannville A	254	226	200	173	145	122	102	86	72	60	51	42	36	30	11	0	0	0
Lathom - Upper Mannville A	391	356	302	257	218	185	157	134	114	97	82	70	59	50	43	36	31	26
Taber - Mannville D	315	308	287	252	222	195	171	150	132	116	102	90	79	70	61	54	47	41
Taber South - Mannville B	189	159	127	97	74	57	43	33	25	19	3	0	0	0	0	0	0	0
Other	1 897	1 878	1 773	1 594	1 432	1 287	1 157	1 040	935	840	755	679	610	549	493	443	398	358
Pipeline Total	**7 885**	**7 670**	**6 932**	**5 941**	**5 099**	**4 391**	**3 794**	**3 289**	**2 859**	**2 491**	**2 165**	**1 894**	**1 663**	**1 450**	**1 246**	**1 090**	**957**	**851**

BP Exploration Canada Limited

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Chauvin - Mannville A	92	85	78	72	67	61	57	52	48	44	41	38	35	32	29	27	25	23
Chauvin South - Sparky A&B	154	162	162	162	160	151	142	134	126	119	112	106	99	94	88	83	78	74
Chauvin South - Sparky E	56	53	49	45	41	38	34	31	29	26	24	22	20	18	17	15	14	13
Chauvin South - Sparky H	148	142	132	117	105	93	83	74	66	59	52	47	42	37	33	30	26	24
Chauvin South - Lloydminster D	36	32	29	25	23	20	18	16	14	13	11	10	9	8	7	6	6	5
Other	168	175	166	150	136	123	111	100	90	81	73	66	60	54	49	44	40	36
Pipeline Total	**655**	**649**	**617**	**573**	**531**	**487**	**445**	**408**	**374**	**343**	**314**	**289**	**265**	**243**	**224**	**206**	**189**	**174**

Husky Pipeline Ltd. & Manito Pipelines Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Lloydminster - Sparky C and GP A	117	113	107	100	93	87	81	76	71	66	62	58	54	50	47	44	41	38
Lloydminster - Sparky and GP C	315	308	295	277	259	242	227	212	198	186	174	163	152	142	133	125	117	109
Viking Kinsella - Wainwright B	1 510	1 480	1 332	1 098	905	745	614	506	417	344	283	233	192	158	130	107	89	73
Wainwright - Wainwright & Sparky A	1 190	1 154	1 074	958	854	761	678	604	539	480	428	382	340	303	270	241	215	191
Wildmere - Lloydminster A & Sparky B	332	329	325	313	293	274	256	240	224	210	196	184	172	161	150	141	132	123
Other	739	725	667	577	498	430	372	321	277	239	207	179	154	133	115	99	86	74
Pipeline Total	**4 203**	**4 110**	**3 803**	**3 322**	**2 902**	**2 540**	**2 229**	**1 960**	**1 727**	**1 526**	**1 350**	**1 198**	**1 065**	**949**	**847**	**757**	**679**	**609**

HEAVY CRUDE OIL

Truck and Tank Car

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Cessford - Total	511	501	469	420	375	336	300	268	240	215	192	171	153	137	123	110	98	88
Other	391	380	369	358	338	312	288	265	245	226	208	192	177	163	150	139	128	118
Pipeline Total	**903**	**881**	**838**	**777**	**714**	**648**	**588**	**534**	**485**	**440**	**400**	**363**	**330**	**300**	**273**	**248**	**226**	**206**
Alberta Total	**13 646**	**13 311**	**12 190**	**10 614**	**9 246**	**8 066**	**7 057**	**6 191**	**5 445**	**4 800**	**4 230**	**3 744**	**3 324**	**2 943**	**2 589**	**2 302**	**2 052**	**1 840**

SASKATCHEWAN

Husky Pipeline Ltd. & Manito Pipelines Ltd.

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Aberfeldy - Sparky, Aberfeldy Unit	601	566	511	440	379	327	281	242	209	180	155	133	115	99	85	74	63	21
South Aberfeldy - Sparky, Voluntary Unit	237	219	196	171	149	129	113	98	85	74	65	56	49	43	37	21	0	0
Dulwich - Sparky	109	105	99	94	88	83	78	73	69	65	61	57	54	51	48	45	42	40
Epping - Sparky and G.P., Non-Unit	238	222	202	179	158	140	125	110	98	87	77	68	60	54	10	0	0	0
South Epping - Sparky and G.P., Unit No. 1	325	300	267	237	211	188	167	149	132	118	105	93	83	74	66	58	52	46
S.W. Epping Sparky Vol. Unit No. 1	147	140	130	118	108	98	89	81	74	67	61	55	50	46	42	38	34	12
Furness - Sparky	49	43	38	34	29	26	23	20	18	16	14	12	10	9	6	0	0	0
Golden Lake North - Waseca & Sparky, Vol. Unit	251	227	203	182	163	146	131	118	105	94	85	76	68	61	55	49	44	39
Golden Lake North - Waseca & Sparky, Non-Unit	109	92	78	66	56	47	40	33	28	24	20	15	0	0	0	0	0	0
Golden Lake South - Sparky	117	112	102	89	77	67	58	50	44	38	33	28	25	21	19	16	14	2
Golden Lake South - Waseca	316	298	268	230	197	169	145	125	107	92	79	68	58	50	43	37	32	27
Gully Lake - Waseca, Vol. Unit No. 1	134	123	113	103	95	87	80	73	67	61	56	52	48	44	40	37	34	31
Gully Lake - Waseca, Non-Unit	97	89	81	74	68	62	57	52	47	43	40	36	33	30	28	25	23	21
Lashburn - Waseca, Vol. Unit	54	50	47	43	41	38	35	33	31	28	27	25	23	21	20	19	17	14
Lone Rock - Sparky	44	39	35	31	28	25	23	20	18	16	14	13	12	10	9	8	0	0
Tangleflags (Total)	578	558	513	448	391	342	299	261	228	199	174	152	133	116	102	89	78	68
Other	1 117	1 095	1 008	869	750	647	558	481	415	358	309	266	230	198	171	148	127	110
Pipeline Total	**4 524**	**4 278**	**3 892**	**3 410**	**2 990**	**2 623**	**2 302**	**2 022**	**1 777**	**1 562**	**1 375**	**1 209**	**1 052**	**929**	**781**	**664**	**561**	**433**

HEAVY CRUDE OIL

Bow River Pipe Lines Ltd. (Heavy Blend)

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Coleville - Bakken	620	584	541	493	449	410	373	340	310	283	258	235	214	195	178	162	148	134
Dodsland - Viking, Eagle Lake, Vol. Unit	184	166	151	138	127	118	110	102	96	90	85	81	76	72	69	66	63	60
Dodsland - Viking, Gleneath Unit	191	184	177	168	157	147	138	130	121	114	107	100	94	88	82	77	72	68
Eureka - Viking, South Unit	126	121	115	108	101	95	89	84	79	74	69	65	61	58	54	51	48	45
North Hoosier - Bakken, Vol. Unit	130	120	111	102	94	87	80	74	68	63	58	54	50	46	42	39	36	33
North Hoosier - Basal Blairmore, Vol. Unit	72	65	59	53	48	43	39	35	31	28	25	23	21	19	17	15	14	2
Smiley Dewar - Viking	279	264	251	238	226	214	203	193	183	174	165	156	148	141	133	126	120	114
Other	496	449	398	353	313	278	246	219	194	172	152	135	120	106	94	84	74	66
Pipeline Total	**2 099**	**1 954**	**1 803**	**1 654**	**1 517**	**1 393**	**1 280**	**1 177**	**1 083**	**998**	**920**	**849**	**784**	**725**	**670**	**621**	**575**	**523**

South Saskatchewan Pipe Line Company

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Battrum - Roseray, Unit No. 1	399	373	349	326	305	285	266	249	233	218	204	190	178	166	155	145	136	127
Cantuar Main - Cantuar, Unit	388	341	299	263	231	203	178	157	138	121	106	94	82	72	63	56	36	0
Dollard - Upper Shaunavon, Unit	837	740	654	577	510	451	399	352	311	275	243	215	190	168	148	131	116	102
Fosterton - Roseray, Main Unit	490	455	423	393	365	338	314	292	271	252	234	217	202	187	174	161	150	139
Gull Lake North - Upper Shaunavon, Unit	191	167	147	128	113	99	87	76	67	58	51	45	39	34	4	0	0	0
Instow - Upper Shaunavon, Unit	601	536	478	427	381	340	303	270	241	215	192	171	153	136	122	109	97	86
Main Success - Roseray, Unit	109	99	91	83	75	68	62	57	52	47	43	39	36	8	0	0	0	0
North Premier - Roseray, Unit No. 3	179	145	117	95	77	62	50	41	16	0	0	0	0	0	0	0	0	0
Rapdan - Upper Shaunavon, Unit	333	303	275	250	227	207	188	171	155	141	128	116	106	96	87	79	72	66
South Success - Roseray, Unit	188	174	161	149	137	127	117	109	100	93	86	79	73	68	63	58	54	50
Suffield - Upper Shaunavon, Unit No. 2	96	88	80	74	68	62	57	52	48	44	40	37	34	31	28	26	24	22
Verlo - Roseray, Unit	375	334	297	264	235	209	186	166	147	131	117	104	92	82	73	65	58	51
Other	2 700	2 473	2 265	2 074	1 899	1 740	1 593	1 459	1 336	1 224	1 121	1 026	940	861	788	722	661	605
Pipeline Total	**6 886**	**6 228**	**5 636**	**5 104**	**4 624**	**4 192**	**3 802**	**3 451**	**3 116**	**2 819**	**2 565**	**2 334**	**2 125**	**1 911**	**1 707**	**1 553**	**1 403**	**1 249**

HEAVY CRUDE OIL

Westspur Pipe Line Company - S.E. Sask. Medium

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Benson - Midale, Unit	134	125	115	107	99	91	85	78	72	67	62	58	53	49	46	42	39	36
Innes - Frobisher	174	161	149	138	128	118	109	101	93	86	80	74	68	63	59	54	50	46
Lost Horse Hill - Frobisher Alida, Vol. Unit No. 1	170	148	129	112	97	84	73	64	55	48	42	36	31	27	24	20	18	15
Midale - Central Midale, Unit	959	894	834	777	725	676	630	587	547	510	476	444	413	386	359	335	312	291
Midale - Central Midale, Non-Unit	173	163	149	133	119	106	95	85	76	68	61	54	48	43	38	34	31	27
Viewfield - Frobisher	169	159	149	140	132	124	116	109	102	96	90	85	79	75	70	66	62	58
Weyburn - Midale, Unit	2 756	2 616	2 483	2 357	2 237	2 124	2 016	1 913	1 816	1 724	1 636	1 553	1 474	1 399	1 328	1 261	1 197	1 136
Weyburn - Midale, Non-Unit	137	126	112	99	88	78	69	61	54	48	42	37	33	29	26	5	0	0
Other	1 280	1 205	1 117	1 017	925	843	767	699	636	579	527	480	437	398	362	330	300	273
Pipeline Total	**5 954**	**5 598**	**5 237**	**4 880**	**4 550**	**4 244**	**3 960**	**3 697**	**3 453**	**3 227**	**3 016**	**2 821**	**2 639**	**2 470**	**2 313**	**2 148**	**2 009**	**1 884**
Saskatchewan Total	**19 463**	**18 058**	**16 568**	**15 048**	**13 681**	**12 451**	**11 344**	**10 347**	**9 430**	**8 607**	**7 877**	**7 214**	**6 601**	**6 034**	**5 471**	**4 985**	**4 549**	**4 089**
Canada - Total Light Crude Oil	**220 728**	**204 382**	**184 528**	**162 664**	**143 108**	**125 218**	**109 727**	**96 369**	**84 947**	**75 183**	**66 777**	**59 445**	**53 023**	**47 420**	**42 597**	**38 474**	**34 729**	**31 224**
Canada - Total Heavy Crude Oil	**33 109**	**31 369**	**28 758**	**25 662**	**22 926**	**20 517**	**18 401**	**16 538**	**14 874**	**13 407**	**12 107**	**10 958**	**9 925**	**8 977**	**8 060**	**7 287**	**6 601**	**5 930**
Canada - Total Crude Oil	**253 837**	**235 751**	**213 286**	**188 326**	**166 034**	**145 735**	**128 128**	**112 907**	**99 821**	**88 590**	**78 884**	**70 403**	**62 948**	**56 397**	**50 657**	**45 761**	**41 330**	**37 154**

PENTANES PLUS PRODUCTION

NEB Forecast m^3/d

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
From Established Reserves																		
British Columbia																		
Taylor (Westcoast)	477	477	461	461	461	448	429	429	423	375	359	315	267	254	235	194	165	156
Total	**477**	**477**	**461**	**461**	**461**	**448**	**429**	**429**	**423**	**375**	**359**	**315**	**267**	**254**	**235**	**194**	**165**	**156**
Alberta																		
Bow River Pipe Lines																		
Cessford (HBOG)	18	16	14	12	11	9	8	7	6	6	5	4	4	3	3	3	2	2
Empress (Pacific)	334	331	326	321	318	314	310	310	310	310	310	310	310	310	273	242	212	181
Wayne-Rosedale	19	16	14	13	11	10	9	7	7	6	5	4	4	3	3	3	2	1
Others	79	74	69	65	60	58	54	48	46	43	40	39	37	34	32	30	29	28
Total	**450**	**437**	**423**	**411**	**399**	**391**	**381**	**372**	**369**	**364**	**360**	**358**	**354**	**351**	**311**	**277**	**246**	**212**
Co-ed Pipe Line																		
Cochrane	222	222	222	222	222	214	204	198	181	164	154	133	121	109	98	91	68	60
Ellerslie (Dome)	26	137	131	127	136	137	137	137	138	131	118	16	16	18	38	40	41	43
Empress (Dome)	258	258	258	258	258	258	253	222	186	150	114	78	40	8	0	0	0	0
Ferrier (Seafort)	28	25	22	19	17	14	13	11	10	8	7	7	6	5	4	3	0	0
Garrington	44	43	37	32	27	24	20	18	15	13	11	10	8	7	6	4	3	3
Minnehik-Buck Lake	164	161	157	138	152	138	119	102	88	76	66	58	50	43	38	33	28	25
Pembina (Texaco)	10	10	9	9	8	8	7	7	7	6	6	6	6	5	5	5	5	4
Quirk Creek	127	124	120	117	108	96	87	78	71	64	58	53	48	43	35	31	28	25
Ricinus	302	270	240	212	187	164	97	120	142	140	139	137	125	109	96	84	74	65
Strachan (Aquitaine)	171	153	136	116	98	84	72	62	53	46	40	34	29	25	21	18	15	13
Strachan (Gulf)	612	533	464	405	354	310	271	238	208	183	160	140	123	108	95	83	73	64
Total	**1 966**	**1 934**	**1 797**	**1 656**	**1 568**	**1 447**	**1 280**	**1 193**	**1 098**	**982**	**873**	**670**	**571**	**482**	**436**	**391**	**335**	**302**
Cremona Pipeline																		
Burnt Timber	65	65	65	65	65	65	65	65	64	58	52	47	42	37	33	30	27	24
Carstairs (Home)	578	531	475	423	378	337	302	270	242	217	195	176	159	143	130	117	106	96
Crossfield (Petrogas)	316	288	263	241	222	204	189	175	163	147	131	118	105	94	84	75	68	61
Crossfield East	93	91	84	77	70	64	58	53	49	45	41	38	35	32	30	28	26	24
Harmattan	906	882	857	791	776	758	740	705	637	581	519	433	362	303	254	213	179	151
Lone Pine Creek (Can. Sup.)	49	44	38	33	29	25	21	19	16	14	12	11	10	8	7	6	5	4
Lone Pine Creek (HBOG)	162	152	143	135	126	110	96	83	73	64	55	48	42	37	25	17	15	13
Olds	75	69	63	58	54	49	46	42	39	36	33	31	29	27	25	23	21	20
Others	8	8	8	8	8	7	6	6	5	5	4	4	4	3	3	3	3	3
Total	**2 251**	**2 130**	**1 997**	**1 830**	**1 725**	**1 619**	**1 522**	**1 418**	**1 288**	**1 166**	**1 044**	**905**	**786**	**685**	**591**	**512**	**450**	**396**
Federated Pipe Lines																		
Virginia Hills (Shell)	16	16	15	14	12	11	10	9	8	7	7	6	6	5	5	4	4	3
Others	2	2	2	2	2	2	2	2	1	1	1	1	1	1	0	0	0	0
Total	**18**	**18**	**17**	**15**	**14**	**13**	**12**	**11**	**10**	**9**	**8**	**7**	**6**	**6**	**5**	**4**	**4**	**3**

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Gibson Petroleum																		
Acheson	20	21	21	21	20	16	13	10	8	6	5	4	3	2	2	1	1	1
Ferrybank	19	19	19	19	18	16	14	12	11	10	9	7	7	6	5	5	4	3
Niton (Dome)	19	16	14	12	11	9	8	7	6	5	4	4	3	3	1	0	0	0
Okotoks	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	8	7
Paddle River	68	68	68	68	68	68	68	68	67	59	53	47	41	37	33	29	26	23
Wilson Creek	28	27	26	26	24	21	18	16	13	12	10	9	8	7	7	6	5	4
Worsley	47	38	30	24	19	15	12	10	8	6	5	4	3	0	0	0	0	0
Others	7	6	4	4	3	3	2	1	1	1	0	0	0	0	0	0	0	0
Total	**217**	**203**	**192**	**182**	**171**	**157**	**144**	**133**	**123**	**108**	**96**	**84**	**75**	**64**	**56**	**50**	**44**	**39**
Gulf Alberta Pipe Line																		
Ghost Pine (Gulf)	33	33	32	31	27	24	21	19	17	15	13	12	10	9	8	7	6	6
Ghost Pine (Mobil)	29	35	32	29	27	25	24	21	20	19	18	17	16	14	14	13	12	11
Hussar (CDC)	25	24	22	20	18	17	16	15	14	12	11	11	10	9	8	8	7	7
Mikwan	6	6	5	4	4	3	3	3	2	2	2	2	2	1	1	1	0	0
Nevis (Chevron)	111	92	75	61	50	41	34	28	23	0	0	0	0	0	0	0	0	0
Nevis (Gulf)	180	168	157	144	129	112	98	100	86	92	79	68	59	51	44	35	26	21
Penhold	5	5	5	4	4	4	4	3	3	3	3	3	3	2	2	2	2	2
Others	39	38	37	37	36	36	34	32	31	30	29	27	26	25	24	24	24	23
Total	**428**	**399**	**364**	**331**	**296**	**263**	**233**	**221**	**195**	**174**	**155**	**138**	**124**	**112**	**102**	**90**	**77**	**69**
Imperial Pipe Line - Ellerslie																		
Golden Spike	140	140	140	140	140	140	140	140	140	52	52	52	52	52	52	52	52	52
Others	22	20	18	15	12	10	9	7	6	5	4	4	3	2	2	2	1	1
Total	**162**	**160**	**157**	**155**	**152**	**150**	**148**	**147**	**146**	**58**	**57**	**56**	**55**	**55**	**54**	**54**	**54**	**54**
Imperial Pipe Line - Leduc																		
Judy Creek	860	846	832	765	682	609	543	486	435	389	349	314	282	253	228	205	185	167
Leduc - Woodbend	68	64	59	52	46	40	34	30	59	63	67	64	62	60	58	53	51	47
Total	**928**	**910**	**891**	**818**	**728**	**649**	**578**	**515**	**494**	**452**	**416**	**378**	**344**	**313**	**286**	**259**	**236**	**214**
Imperial PipeLine - Redwater																		
Redwater	102	102	94	75	59	47	37	29	23	18	14	11	9	7	6	4	0	0
Total	**102**	**102**	**94**	**75**	**59**	**47**	**37**	**29**	**23**	**18**	**14**	**11**	**9**	**7**	**6**	**4**	**0**	**0**
Murphy Oil																		
Total	12	11	11	10	10	10	**9**	**9**	**9**	**9**	**8**	**8**	**8**	**7**	**6**	**6**	**5**	**5**

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Peace River Oil Pipeline																		
Carson Creek	277	273	268	259	241	222	195	177	160	143	125	110	97	85	75	66	58	51
Dunvegan	210	218	219	219	220	221	221	208	178	154	132	114	99	85	74	63	54	46
Gold Creek	146	133	120	109	99	89	81	72	65	59	54	49	45	41	38	34	23	0
Greencourt	18	18	18	18	18	18	17	15	13	12	10	9	8	7	6	5	4	4
Kaybob	58	57	55	52	48	44	40	36	32	29	27	24	22	20	18	16	14	13
Kaybob South	5 583	5 094	4 635	4 205	3 801	3 421	3 065	2 498	2 391	2 095	1 746	1 459	1 226	1 032	871	737	625	530
Simonette (Shell)	38	46	46	45	43	41	37	32	29	25	22	20	17	15	14	12	10	6
Sturgeon Lake South	85	90	89	82	74	67	61	55	50	45	41	37	34	30	27	25	23	20
Whitecourt	40	38	36	34	32	31	29	25	21	18	16	14	12	10	9	7	6	6
Windfall	579	529	485	446	411	243	239	235	223	170	125	92	68	50	37	28	21	15
Others	5	5	5	4	4	4	4	3	3	2	2	2	2	2	1	1	1	1
Total	**7 039**	**6 500**	**5 977**	**5 473**	**4 991**	**4 401**	**3 989**	**3 356**	**3 166**	**2 752**	**2 300**	**1 930**	**1 628**	**1 378**	**1 170**	**995**	**840**	**692**
Pembina Pipe Line																		
Brazeau (HBOG)	238	236	234	227	221	215	210	205	199	195	181	160	142	127	113	101	90	81
Brazeau (CDC)	74	74	71	69	67	65	59	50	43	37	31	27	23	20	17	15	13	11
Niton (Norcen)	3	3	2	2	2	1	1	1	1	1	0	0	0	0	0	0	0	0
Peco	70	65	60	55	51	48	45	42	37	33	30	26	24	21	18	16	14	13
Willesden Green	23	20	18	16	14	13	11	10	9	8	7	6	6	5	0	0	0	0
Others	35	31	28	25	22	21	21	20	20	18	17	17	16	15	14	13	13	11
Total	**443**	**429**	**413**	**394**	**378**	**363**	**348**	**328**	**309**	**291**	**267**	**237**	**211**	**188**	**162**	**145**	**130**	**116**
Rainbow Pipe Line																		
Mitsue	76	78	79	73	66	60	54	48	44	39	36	32	29	26	24	21	19	17
Nipisi	119	126	132	131	126	108	92	78	67	57	48	41	35	30	25	22	18	16
Swan Hills (Shell)	15	14	14	13	12	11	11	10	10	9	9	8	8	8	7	7	7	6
Total	**210**	**218**	**224**	**217**	**204**	**179**	**157**	**137**	**120**	**105**	**93**	**81**	**72**	**63**	**56**	**50**	**44**	**39**
Rangeland Pipe Line																		
Caroline (Altana)	36	34	32	30	27	26	23	19	16	13	11	10	8	7	6	5	4	4
Caroline (HBOG)	96	89	82	76	71	67	60	52	46	40	35	31	27	24	21	18	16	14
Ferrier (Amerada)	229	224	214	190	169	150	132	116	104	92	82	73	65	58	52	46	39	35
Gilby (Texaco)	95	94	89	83	78	72	67	61	57	53	50	47	44	38	33	28	24	21
Gilby (Others)	99	88	78	70	63	57	51	47	42	39	34	30	26	23	14	12	11	10
Innisfail	21	23	24	25	25	22	18	15	13	11	9	7	6	5	4	4	3	3
Joffre (Imperial)	5	5	5	5	5	5	5	4	4	4	3	3	3	3	3	3	3	2
Pincher Creek	145	107	80	61	47	37	29	23	18	15	12	7	5	5	4	3	3	0
Sylvan Lake (Chevron)	39	34	30	26	23	20	18	15	13	12	10	9	8	7	7	6	5	5
Sylvan Lake (HBOG)	68	58	51	44	39	35	31	28	25	23	22	18	15	13	12	10	9	8
Sylvan Lake (Others)	48	43	39	35	32	29	27	25	23	21	20	19	17	14	7	6	6	5
Waterton	1 515	1 481	1 425	1 511	1 457	1 401	1 341	1 192	1 004	863	755	672	606	553	511	476	446	421
Wimborne (Mobil)	108	89	73	61	50	42	35	29	24	20	17	14	12	10	8	7	6	5
Others	32	29	25	23	21	19	17	15	13	12	10	8	8	7	6	6	5	5
Total	**2 534**	**2 397**	**2 248**	**2 241**	**2 109**	**1 982**	**1 854**	**1 643**	**1 403**	**1 219**	**1 072**	**949**	**852**	**768**	**688**	**630**	**580**	**535**
Rimbey Pipeline																		
Homeglen - Rimbey	1 258	1 250	1 096	910	757	628	523	438	369	312	266	229	199	172	151	128	103	81
Total	**1 258**	**1 250**	**1 096**	**910**	**757**	**628**	**523**	**438**	**369**	**312**	**266**	**229**	**199**	**172**	**151**	**128**	**103**	**81**

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Texaco Exploration																		
Bonnie Glen	705	712	720	713	655	591	526	474	312	301	295	292	293	289	254	223	200	182
Total	**705**	**712**	**720**	**713**	**655**	**591**	**526**	**474**	**312**	**301**	**295**	**292**	**293**	**289**	**254**	**223**	**200**	**182**
Valley Pipe Line																		
Jumping Pound	442	428	413	389	369	351	335	320	303	288	274	262	250	241	232	223	202	180
Turner Valley	59	54	49	45	41	37	34	31	28	26	24	22	20	18	17	15	14	13
Wildcat Hills	106	104	103	102	101	101	99	97	86	76	67	59	52	46	41	36	32	28
Total	**606**	**586**	**565**	**536**	**511**	**489**	**468**	**447**	**418**	**390**	**365**	**343**	**323**	**305**	**289**	**274**	**248**	**220**
Truck and Tank Car																		
Boundary Lake South (Imperial)	11	10	8	7	6	5	5	4	3	3	2	2	2	2	1	1	1	0
Edson	303	299	278	240	208	181	157	136	118	102	89	77	67	58	51	44	38	33
Rosevear (Sun)	33	33	33	33	33	33	33	33	33	31	27	22	19	16	13	11	9	8
Niton	19	16	14	12	11	9	8	7	6	5	4	4	3	3	1	0	0	0
Others	107	111	121	131	141	146	153	162	173	191	194	197	200	176	167	159	148	138
Total	**473**	**470**	**454**	**424**	**399**	**375**	**356**	**342**	**334**	**332**	**316**	**302**	**291**	**255**	**233**	**215**	**196**	**180**
Alberta Total	**19 803**	**18 868**	**17 641**	**16 393**	**15 127**	**13 753**	**12 565**	**11 215**	**10 185**	**9 042**	**8 004**	**6 980**	**6 201**	**5 500**	**4 855**	**4 307**	**3 793**	**3 341**
Saskatchewan																		
Total	**116**	**109**	**102**	**96**	**90**	**77**	**65**	**55**	**47**	**40**	**36**	**32**	**28**	**25**	**22**	**20**	**18**	**16**
Total Canada	20 395	19 453	18 204	16 950	15 679	14 278	13 060	11 699	10 655	9 457	8 398	7 326	6 496	5 779	5 113	4 521	3 976	3 513
Less Injection	437	397	358	318	278	238	199	159	0	0	0	0	0	0	0	0	0	0
Sub Total	19 958	19 056	17 847	16 632	15 401	14 040	12 861	11 540	10 655	9 457	8 398	7 326	6 496	5 779	5 113	4 521	3 976	3 513
From Reserves Additions	**596**	**1 199**	**1 935**	**2 397**	**3 180**	**4 077**	**4 430**	**4 724**	**4 786**	**4 998**	**5 155**	**5 166**	**4 958**	**4 921**	**4 815**	**4 720**	**4 427**	**4 186**
Total	**20 555**	**20 255**	**19 782**	**19 030**	**18 581**	**18 116**	**17 291**	**16 264**	**15 442**	**14 455**	**13 553**	**12 493**	**11 454**	**10 701**	**9 928**	**9 240**	**8 403**	**7 698**

POTENTIAL PRODUCIBILITY FROM OIL SANDS

NEB Forecast

Base Case

$10^3 m^3/d$

Year	Miscell-aneous In Situ	GCOS	Syncrude	Syncrude Expansion	Cold Lake* In Situ	3rd* Mining	Undefined Project	Undefined Project	Undefined Project	Undefined Project	Total
1978	1	7	4	-	-	-	-	-	-	-	12
1979	2	7	14	-	-	-	-	-	-	-	23
1980	2	7	16	-	-	-	-	-	-	-	25
1981	2	7	17	-	-	-	-	-	-	-	26
1982	2	7	19	-	-	-	-	-	-	-	28
1983	3	9	20	-	-	-	-	-	-	-	32
1984	4	10	20	-	-	-	-	-	-	-	34
1985	5	10	20	6	-	-	-	-	-	-	41
1986	5	10	20	8	-	-	-	-	-	-	43
1987	5	10	20	10	8	-	-	-	-	-	53
1988	5	10	20	10	16	10	-	-	-	-	71
1989	5	10	20	10	21	14	-	-	-	-	80
1990	5	10	20	10	23	19	-	-	-	-	87
1991	5	10	20	10	23	20	6	-	-	-	94
1992	5	10	20	10	23	20	12	-	-	-	100
1993	5	10	20	10	23	20	20	-	-	-	108
1994	5	10	20	10	23	20	20	6	-	-	114
1995	5	10	20	10	23	20	20	12	-	-	120

* 3rd mining and 1st In Situ plant considered to have equal opportunity to start up in 1987, but because of the magnitude of these projects, it is considered unlikely that both projects will start up in 1987.

POTENTIAL PRODUCIBILITY FROM OIL SANDS

NEB Forecast

High Case

$10^3 m^3/d$

Year	Miscell-aneous In Situ	GCOS	Syncrude	Syncrude Expansion	Cold Lake In Situ	3rd Mining	Undefined Project	Undefined Project	Undefined Project	Undefined Project	Total
1978	1	7	4	-	-	-	-	-	-	-	12
1979	2	7	17	-	-	-	-	-	-	-	26
1980	2	7	17	-	-	-	-	-	-	-	26
1981	3	9	17	-	-	-	-	-	-	-	29
1982	4	10	19	-	-	-	-	-	-	-	33
1983	5	10	21	-	-	-	-	-	-	-	36
1984	5	10	21	4	-	-	-	-	-	-	40
1985	5	10	21	8	-	-	-	-	-	-	44
1986	5	10	21	10	6	10	-	-	-	-	62
1987	5	10	21	10	16	14	-	-	-	-	76
1988	5	10	21	10	21	19	-	-	-	-	86
1989	5	10	21	10	23	20	6	-	-	-	95
1990	5	10	21	10	23	20	16	-	-	-	105
1991	5	10	21	10	23	20	21	6	-	-	116
1992	5	10	21	10	34	29	22	16	-	-	147
1993	5	10	21	10	34	29	22	21	6	-	158
1994	5	10	21	10	34	29	22	22	16	-	169
1995	5	10	21	10	34	29	33	22	21	6	191

POTENTIAL PRODUCIBILITY FROM OIL SANDS

NEB Forecast

Low Case
$10^3 m^3/d$

Year	Miscell-aneous In Situ	GCOS	Syncrude	Syncrude Expansion	Cold Lake In Situ	3rd Mining	Undefined Project	Undefined Project	Undefined Project	Undefined Project	Total
1978	1	7	4	-	-	-	-	-	-	-	12
1979	1	7	14	-	-	-	-	-	-	-	22
1980	1	7	16	-	-	-	-	-	-	-	24
1981	1	7	17	-	-	-	-	-	-	-	25
1982	1	7	19	-	-	-	-	-	-	-	27
1983	1	7	20	-	-	-	-	-	-	-	28
1984	1	7	20	-	-	-	-	-	-	-	28
1985	1	7	20	-	-	-	-	-	-	-	28
1986	1	7	20	-	-	-	-	-	-	-	28
1987	1	7	20	-	-	-	-	-	-	-	28
1988	1	7	20	-	-	-	-	-	-	-	28
1989	1	7	20	-	-	-	-	-	-	-	28
1990	1	7	20	-	-	-	-	-	-	-	28
1991	1	7	20	-	-	-	-	-	-	-	28
1992	1	7	20	-	-	-	-	-	-	-	28
1993	1	7	20	-	-	-	-	-	-	-	28
1994	1	7	20	-	-	-	-	-	-	-	28
1995	1	7	20	-	-	-	-	-	-	-	28

POTENTIAL PRODUCIBILITY OF CRUDE OIL AND EQUIVALENT

Base Case

$10^3 m^3/d$

	Light Crude Oil and Equivalent						Heavy Crude Oil						Total Crude Oil and Equivalent					
	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands (Synthetic)	Upgraded Heavy	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrader Feed-Stock	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrading Loss	Total
1978	221	2	19	11	-	253	33	1	2	1	-	37	254	3	21	12	-	290
1979	204	5	18	21	-	248	31	3	2	2	-	38	235	8	20	23	-	286
1980	185	9	18	23	-	235	29	5	2	2	-	38	214	14	20	25	-	273
1981	163	13	17	25	-	218	26	6	2	2	-	36	189	19	19	27	-	254
1982	143	16	16	26	-	201	23	8	2	2	-	35	166	24	18	28	-	236
1983	125	20	16	29	-	190	21	9	3	3	-	36	146	29	19	32	-	226
1984	110	22	14	30	-	176	18	11	3	4	-	36	128	33	17	34	-	212
1985	96	24	14	36	7	177	17	12	2	5	(8)	28	113	36	16	41	(1)	205
1986	85	26	14	38	7	170	15	14	2	5	(8)	28	100	40	16	43	(1)	198
1987	75	27	12	48	7	169	13	16	2	5	(8)	28	88	43	14	53	(1)	197
1988	67	28	11	66	7	179	12	18	2	5	(8)	29	79	46	13	71	(1)	208
1989	59	28	10	76	7	180	11	20	2	5	(8)	30	70	48	13	80	(1)	210
1990	53	29	9	83	7	181	10	22	2	5	(8)	31	63	51	11	88	(1)	212
1991	47	30	8	89	7	181	9	23	3	5	(8)	32	56	53	11	94	(1)	213
1992	43	31	7	95	7	183	8	24	3	5	(8)	32	51	55	10	100	(1)	215
1993	38	31	7	103	7	186	7	25	3	5	(8)	32	46	56	9	108	(1)	218
1994	35	31	6	109	7	188	7	26	3	5	(8)	33	42	57	9	114	(1)	221
1995	31	31	5	115	7	189	6	26	3	5	(8)	32	37	57	8	120	(1)	221

POTENTIAL PRODUCIBILITY OF CRUDE OIL AND EQUIVALENT

High Case

$10^3 m^3/d$

	Light Crude Oil and Equivalent						Heavy Crude Oil						Total Crude Oil and Equivalent					
	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands (Synthetic)	Upgraded Heavy	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrader Feed-Stock	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrading Loss	Total
1978	221	3	19	11	-	254	33	1	2	1	-	37	254	4	21	12	-	291
1979	204	7	18	24	-	253	31	3	2	2	-	38	236	10	20	25	-	291
1980	185	12	17	24	-	238	29	6	3	2	-	40	214	18	20	26	-	278
1981	163	17	16	26	-	222	26	8	3	3	-	40	189	25	19	29	-	262
1982	143	23	15	29	-	210	23	10	3	4	-	40	166	33	18	33	-	250
1983	125	29	15	31	-	200	21	12	3	5	-	41	146	41	18	36	-	241
1984	110	34	14	35	-	193	18	14	3	5	-	40	128	48	17	40	-	233
1985	96	39	14	39	7	195	17	17	2	5	(8)	33	113	56	16	44	(1)	228
1986	85	44	13	56	7	205	15	19	2	5	(8)	33	100	64	15	60	(1)	238
1987	75	48	12	72	7	214	13	22	2	5	(8)	34	88	70	14	77	(1)	248
1988	67	51	11	81	7	217	12	24	3	5	(8)	36	79	75	14	86	(1)	253
1989	59	54	10	90	7	220	11	27	3	5	(8)	38	70	81	13	95	(1)	258
1990	53	56	10	100	14	233	10	29	2	5	(16)	30	63	85	12	105	(2)	263
1991	47	58	9	110	14	238	9	31	2	5	(16)	31	56	89	11	115	(2)	269
1992	43	60	8	143	14	268	8	32	2	5	(16)	31	51	92	10	148	(2)	299
1993	38	61	7	153	14	273	7	35	2	5	(16)	33	45	96	9	158	(2)	306
1994	35	62	6	165	14	282	7	37	2	5	(16)	35	42	99	8	170	(2)	317
1995	31	62	5	187	14	299	6	38	2	5	(16)	35	37	99	8	192	(2)	334

POTENTIAL PRODUCIBILITY OF CRUDE OIL AND EQUIVALENT

Low Case

$10^3 m^3/d$

	Light Crude Oil and Equivalent						Heavy Crude Oil						Total Crude Oil and Equivalent					
	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands (Synthetic)	Upgraded Heavy	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrader Feed-Stock	Sub-Total	Established Reserves	Reserves Additions	Pentanes Plus	Oil Sands	Upgrading Loss	Total
1978	221	1	19	11	-	252	33	1	2	1	-	37	254	2	21	12	-	289
1979	204	4	18	21	-	247	31	2	2	1	-	36	235	6	20	22	-	283
1980	185	6	18	23	-	232	29	3	2	1	-	35	213	10	20	24	-	267
1981	163	9	17	25	-	214	26	4	2	1	-	33	189	13	19	26	-	247
1982	143	11	17	25	-	196	23	5	2	1	-	31	166	16	19	26	-	227
1983	125	14	17	26	-	182	21	6	2	1	-	30	146	20	19	27	-	212
1984	110	15	16	27	-	168	18	6	2	1	-	27	128	21	18	28	-	195
1985	96	17	15	27	-	155	17	7	1	1	-	26	113	24	16	28	-	181
1986	85	18	14	27	-	144	15	7	1	1	-	24	100	25	15	28	-	168
1987	75	19	13	27	-	134	13	8	1	1	-	23	88	27	14	28	-	157
1988	67	19	12	27	-	125	12	9	2	1	-	24	79	28	14	28	-	149
1989	59	19	11	27	-	116	11	10	2	1	-	24	70	29	13	28	-	140
1990	53	19	10	27	-	109	10	11	2	1	-	24	63	30	12	28	-	133
1991	47	19	9	27	-	102	9	12	2	1	-	24	56	31	11	28	-	126
1992	43	19	8	27	-	97	8	12	2	1	-	23	51	31	10	28	-	120
1993	38	18	7	27	-	90	7	13	2	1	-	23	45	31	9	28	-	113
1994	35	18	7	27	-	87	7	14	2	1	-	24	42	32	9	28	-	111
1995	31	18	6	27	-	82	6	14	2	1	-	23	37	32	8	28	-	105

ENERGY DEMAND BY SECTOR

NEB Forecast

(10^{15} joules)

	1978	1980	1985	1990	1995
Residential					
Total Oil	561.1	521.5	495.1	494.3	482.7
Diesel	61.2	56.9	58.2	63.1	67.2
LFO, Kerosene & Stove Oil	475.9	443.6	413.8	404.8	386.4
HFO	24.0	21.0	23.1	26.4	29.1
Natural Gas	344.5	356.5	401.4	465.7	535.2
Electricity	283.6	308.5	371.3	452.3	544.6
Other*	77.2	68.2	69.6	73.7	76.7
Total Energy	1266.4	1254.7	1337.4	1486.0	1639.2
Commercial					
Total Oil	215.7	212.3	214.6	224.9	235.8
Diesel	22.5	24.3	25.8	27.1	28.2
LFO, Kerosene & Stove Oil	97.9	96.3	96.4	99.9	103.4
HFO	95.3	91.7	92.4	97.9	104.2
Natural Gas	331.2	354.0	430.2	499.8	581.9
Electricity	270.5	306.2	425.8	538.9	669.6
Other*	0	0	0	0	0
Total Energy	817.4	872.5	1070.6	1263.6	1487.3
Industrial					
Total Oil	579.8	604.4	658.8	690.3	772.0
Diesel	148.1	149.5	161.6	174.0	194.4
LFO, Kerosene & Stove Oil	71.0	73.4	79.1	80.1	90.4
HFO	360.7	381.5	418.1	436.2	487.2
Natural Gas	562.1	618.1	730.4	812.7	995.1
Electricity	460.1	506.2	588.6	693.4	817.9
Other*	289.1	309.0	343.2	357.6	383.5
Total Energy**	1891.1	2037.7	2321.0	2554.0	2968.5
Petrochemical					
Total Oil	157.5	197.7	306.7	357.0	357.0
Natural Gas	162.0	200.5	271.7	306.3	323.9
Other*	24.9	24.9	24.9	37.5	37.5
Total Energy	344.4	423.1	603.3	700.8	718.4

* includes all LPG's, coal and renewable energy.

** Total energy for the industrial sector excludes requirements for the production of petrochemicals; and includes coal used to produce coke and coke oven gas.

ENERGY DEMAND BY SECTOR

NEB Forecast

(10^{15} joules)

	1978	1980	1985	1990	1995
Transportation					
Total Oil	1760.3	1845.2	1990.6	2115.9	2270.5
Total Energy	1762.8	1847.7	1993.1	2118.4	2273.0
Road					
Total Oil	1403.5	1450.6	1502.7	1557.8	1636.0
Motor Gasoline	1287.6	1310.6	1281.4	1239.1	1206.9
Diesel	115.9	140.0	220.3	318.7	428.2
Total Energy	1403.5	1450.6	1502.7	1557.8	1636.0
Rail					
Total Oil	102.6	107.8	122.3	136.0	153.9
Diesel	92.1	96.7	109.7	121.8	137.7
LFO and Kerosene	2.8	3.0	3.7	1.3	5.1
HFO	7.7	8.0	9.0	9.9	11.1
Coal	1.7	1.6	1.5	1.4	1.3
Total Energy	104.3	109.4	123.8	137.4	155.2
Air					
Total Oil	152.8	174.9	231.8	276.2	319.8
Aviation Gasoline	8.8	9.3	9.1	10.2	11.5
Aviation Turbo Fuel	144.0	165.6	222.7	265.9	308.3
Total Energy	152.8	174.9	231.8	276.2	319.8
Marine					
Total Oil	101.4	111.9	133.8	145.9	160.8
Diesel	28.0	31.6	39.8	46.7	55.1
LFO and Kerosene	.7	.7	1.0	1.3	1.6
HFO	72.7	79.6	93.0	97.9	104.0
Coal	.8	.9	1.0	1.1	1.2
Total Energy	102.2	112.8	134.8	147.0	162.0

EXPORT DEMAND BY SECTOR

Export Formula Case

(10^{15} joules)

	1978	1980	1985	1990	1995
Residential					
Total Oil	626.7	619.0	649.5	683.6	701.7
Total Energy	1355.6	1406.3	1610.1	1819.8	2023.3
Commercial					
Total Oil	240.6	242.3	260.4	300.0	342.7
Total Energy	893.4	984.4	1303.3	1639.8	2000.3
Industrial					
Total Oil	593.6	649.2	803.6	939.2	1110.3
Total Energy	1936.3	1180.0	2770.2	3346.2	4047.5
Petrochemicals					
Total Oil	157.5	197.7	306.7	357.0	357.0
Total Energy	344.5	423.1	603.3	700.8	718.4
Transportation					
Total Oil	1905.7	2065.0	2491.8	2960.5	3479.6
Total Energy	1908.6	2067.9	2494.5	2963.4	3482.6
Road					
Total Oil	1526.5	1644.8	1958.7	2333.3	2743.3
Total Energy	1526.5	1644.8	1958.7	2333.3	2743.3
Rail					
Total Oil	105.2	113.4	131.6	148.6	171.0
Total Energy	106.9	115.2	133.2	150.2	172.5
Air					
Total Oil	152.8	174.9	244.0	306.9	376.2
Total Energy	152.8	174.9	244.0	306.9	376.2
Marine					
Total Oil	121.2	131.9	157.5	171.7	189.1
Total Energy	122.4	133.0	158.6	173.0	190.6

Note: Oil data excludes all LPG's.

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Canada

$10^3 m^3/d$

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	101.7	103.2	103.7	101.4	98.0	95.4
Light Fuel Oil, Kerosene and Stove Oil	46.8	45.6	44.7	42.9	42.6	42.1
Diesel Fuel Oil	34.2	35.3	36.7	44.8	54.8	66.5
Heavy Fuel Oil	46.8	48.6	49.9	52.9	52.7	58.5
Petrochemical Feedstocks	11.1	12.6	14.0	21.9	25.4	25.4
Other Products	34.8	35.8	37.7	45.3	52.6	60.2
Total All Products	275.4	281.1	286.7	309.2	326.1	348.1
Export Formula Case Total All Products	294.9	305.9	315.4	371.1	426.2	480.5

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

East of the Ottawa Valley

$10^3 m^3/d$

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	36.2	36.5	36.5	34.6	32.7	31.2
Light Fuel Oil, Kerosene and Stove Oil	27.6	27.1	26.7	26.2	26.3	26.4
Diesel Fuel Oil	11.2	11.5	11.9	14.2	16.9	20.1
Heavy Fuel Oil	31.7	33.5	34.9	37.0	36.6	41.2
Petrochemical Feedstocks	3.1	3.1	3.1	5.6	5.6	5.6
Other Products	12.6	12.6	13.5	16.4	19.0	21.5
Total All Products	122.4	124.3	126.6	134.0	137.1	146.0
Export Formula Case Total All Products	134.3	139.2	142.9	165.4	186.8	208.4

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

West of the Ottawa Valley

$10^3 m^3/d$

NEB Forecast	1978	1979	1980	1985	1990	1995
Motor Gasoline	65.5	66.7	67.2	66.8	65.3	64.2
Light Fuel Oil, Kerosene and Stove Oil	19.2	18.5	18.0	16.7	16.3	15.7
Diesel Fuel Oil	23.0	23.8	24.8	30.6	37.9	46.4
Heavy Fuel Oil	15.1	15.1	15.0	15.9	16.1	17.3
Petrochemical Feedstocks	8.0	9.5	10.9	16.3	19.8	19.8
Other Products	22.2	23.2	24.2	28.9	33.6	38.7
Total All Products	153.0	156.8	160.1	175.2	189.0	202.1
Export Formula Case Total All Products	160.6	166.7	172.5	205.7	239.4	272.1

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Atlantic

$10^3 m^3/d$

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	8.4	8.5	8.5	8.4	8.2	7.9
Light Fuel Oil, Kerosene and Stove Oil	7.9	7.7	7.6	7.9	8.3	8.6
Diesel Fuel Oil	3.8	4.0	4.1	4.6	5.4	6.3
Heavy Fuel Oil	13.6	14.8	14.9	15.7	14.4	16.4
Petrochemical Feedstocks	0.1	0.1	0.1	0.1	0.1	0.1
Other Products	2.7	2.9	3.0	3.5	4.1	4.7
Total All Products	36.5	38.0	38.2	40.2	40.5	44.0
Export Formula Case						
Total All Products	41.4	43.6	44.8	48.5	54.5	59.6

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Quebec

$10^3 m^3/d$

NEB Forecast	1978	1979	1980	1985	1990	1995
Motor Gasoline	24.1	24.3	24.3	22.7	21.2	20.2
Light Fuel Oil, Kerosene and Stove Oil	17.9	17.7	17.5	16.8	16.6	16.4
Diesel Fuel Oil	6.5	6.6	6.8	8.3	9.9	11.8
Heavy Fuel Oil	16.9	17.5	18.8	20.1	21.0	23.5
Petrochemical Feedstocks	3.0	3.0	3.0	5.5	5.5	5.5
Other Products	8.9	8.6	9.4	11.6	13.4	15.1
Total All Products	77.3	77.7	79.8	85.0	87.6	92.5
Export Formula Case						
Total All Products	83.2	85.6	87.7	105.0	118.7	133.8

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Ontario

$10^3 m^3/d$

NEB Forecast	1978	1979	1980	1985	1990	1995
Motor Gasoline	36.5	37.0	37.1	35.3	32.9	30.7
Light Fuel Oil, Kerosene and Stove Oil	14.8	13.9	13.3	12.3	11.8	11.4
Diesel Fuel Oil	8.1	8.5	8.9	11.4	14.4	17.9
Heavy Fuel Oil	11.9	11.7	11.7	11.7	11.7	12.1
Petrochemical Feedstocks	7.9	9.4	10.8	13.0	16.5	16.5
Other Products	11.4	11.8	12.3	14.3	16.7	19.0
Total All Products	90.6	92.3	94.1	98.0	104.0	107.6
Export Formula Case Total All Products	97.0	100.4	104.1	118.8	136.2	150.3

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Ottawa Valley

$10^3 m^3/d$

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	3.7	3.7	3.7	3.5	3.3	3.1
Light Fuel Oil, Kerosene and Stove Oil	1.8	1.7	1.6	1.5	1.4	1.4
Diesel Fuel Oil	0.9	0.9	1.0	1.3	1.6	2.0
Heavy Fuel Oil	1.2	1.2	1.2	1.2	1.2	1.3
Petrochemical Feedstocks	-	-	-	-	-	-
Other Products	1.0	1.1	1.1	1.3	1.5	1.7
Total All Products	8.6	8.6	8.6	8.8	9.0	9.5
Export Formula Case Total All Products	9.7	10.0	10.4	11.9	13.6	15.0

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Manitoba

$10^3 m^3/d$

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	4.5	4.6	4.6	4.5	4.4	4.4
Light Fuel Oil, Kerosene and Stove Oil	0.9	0.9	0.9	0.8	0.8	0.7
Diesel Fuel Oil	2.0	2.1	2.1	2.5	3.0	3.5
Heavy Fuel Oil	0.4	0.4	0.4	0.4	0.4	0.4
Petrochemical Feedstocks	-	-	-	-	-	-
Other Products	1.4	1.4	1.4	1.8	2.0	2.4
Total All Products	9.2	9.4	9.4	10.0	10.6	11.4
Export Formula Case Total All Products	9.6	9.8	10.1	12.0	13.8	15.7

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Saskatchewan

$10^3 m^3/d$

NEB Forecast	1978	1979	1980	1985	1990	1995
Motor Gasoline	5.8	5.8	5.7	5.5	5.3	5.1
Light Fuel Oil, Kerosene and Stove Oil	1.1	1.1	1.1	1.0	1.0	1.1
Diesel Fuel Oil	2.6	2.6	2.7	3.1	3.8	4.4
Heavy Fuel Oil	0.1	0.1	-	-	-	0.1
Petrochemical Feedstocks	-	-	-	-	-	-
Other Products	1.0	1.2	1.2	1.4	1.6	2.0
Total All Products	10.6	10.8	10.7	11.0	11.7	12.7
Export Formula Case						
Total All Products	10.9	11.2	11.3	13.0	15.0	17.1

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Alberta

$10^3 m^3/d$

NEB Forecast	1978	1979	1980	1985	1990	1995
Motor Gasoline	11.7	12.1	12.4	13.1	13.4	13.5
Light Fuel Oil, Kerosene and Stove Oil	0.5	0.5	0.5	0.4	0.4	0.4
Diesel Fuel Oil	5.3	5.4	5.5	7.1	8.9	11.0
Heavy Fuel Oil	0.1	0.2	0.1	0.2	0.2	0.2
Petrochemical Feedstocks	-	-	-	3.2	3.2	3.2
Other Products	5.0	5.3	5.5	6.7	7.9	9.0
Total All Products	22.6	23.5	24.0	30.7	34.0	37.3
Export Formula Case Total All Products	23.7	24.9	25.9	35.7	42.4	49.1

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

British Columbia

$10^3 m^3/d$

NEB Forecast	1978	1979	1980	1985	1990	1995
Motor Gasoline	10.4	10.6	10.8	11.6	12.3	13.3
Light Fuel Oil, Kerosene and Stove Oil	3.2	3.3	3.3	3.2	3.2	3.1
Diesel Fuel Oil	5.3	5.5	5.9	7.0	8.4	10.4
Heavy Fuel Oil	3.7	3.8	3.9	4.7	4.9	5.7
Petrochemical Feedstocks	0.1	0.1	0.1	0.1	0.1	0.1
Other Products	4.0	4.2	4.4	5.4	6.2	7.2
Total All Products	26.7	27.5	28.4	32.0	35.1	39.8
Export Formula Case Total All Products	27.2	28.4	29.4	35.6	42.6	51.3

PETROLEUM PRODUCT DEMAND

NEB Forecast and NEB Export Formula Case

Yukon & N.W.T.

$10^3 m^3/d$

	1978	1979	1980	1985	1990	1995
NEB Forecast						
Motor Gasoline	0.3	0.3	0.3	0.3	0.3	0.3
Light Fuel Oil, Kerosene and Stove Oil	0.5	0.5	0.5	0.5	0.5	0.4
Diesel Fuel Oil	0.6	0.6	0.7	0.8	1.0	1.2
Heavy Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1
Petrochemical Feedstocks	-	-	-	-	-	-
Other Products	0.4	0.4	0.5	0.6	0.7	0.8
Total All Products	1.9	1.9	2.1	2.3	2.6	2.8
Export Formula Case Total All Products	1.9	2.0	2.1	2.8	3.0	3.6

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Canada

($10^3 m^3/d$)

Motor Gasoline	Gulf	Imperial (1)	Shell (2)	Texaco	NEB
1978	100.4	98.5	100.3	99.3	101.7
1980	103.6	99.8	103.3	101.5	103.7
1985	102.5	95.7	100.7	101.1	101.4
1990	98.2	93.8	94.5	98.4	98.0
1995	96.0	92.6	93.4	95.2	95.4
Light Fuel Oil, Kerosene and Stove Oil					
1978	45.9	45.4	48.5	46.6	46.8
1980	42.7	42.6	47.5	44.3	44.7
1985	36.9	34.6	47.5	41.6	42.9
1990	33.2	29.2	46.2	39.9	42.6
1995	31.1	24.8	47.5	38.3	42.1
Diesel Fuel Oil					
1978	34.6	34.6	35.3	35.3	34.2
1980	37.0	37.7	39.7	38.6	36.7
1985	47.4	46.2	50.4	46.6	44.8
1990	58.5	55.9	61.7	54.8	54.8
1995	70.4	65.9	74.8	62.3	66.5
Heavy Fuel Oil					
1978	48.0	47.0	45.4	46.7	46.8
1980	48.0	49.9	46.7	47.7	49.9
1985	47.7	45.0	52.6	49.3	52.9
1990	50.2	46.9	56.3	51.2	52.7
1995	53.1	48.3	62.3	53.4	58.5
Petrochemical Feedstocks					
1978	10.8	13.7	13.0	13.8	11.1
1980	15.7	15.7	14.8	15.1	14.0
1985	17.6	18.1	15.9	19.7	21.9
1990	18.8	22.1	19.2	21.8	25.4
1995	19.7	28.3	22.7	23.7	25.4
Other Products					
1978	30.5	33.5	31.8	33.8	34.8
1980	31.8	33.7	34.2	36.7	37.7
1985	36.1	39.1	40.0	43.2	45.3
1990	40.4	45.3	45.8	49.4	52.6
1995	45.1	51.8	52.1	55.9	60.2
Total All Products					
1978	270.3	272.8	274.3	275.5	275.4
1980	278.7	279.3	286.2	284.0	286.7
1985	288.1	278.7	307.2	301.4	309.2
1990	299.2	293.2	323.7	315.4	326.1
1995	315.4	311.8	352.8	328.8	348.;

Note: Totals might not add due to rounding.

(1) Imperial's demand numbers for petrochemical feedstocks and other products were adjusted for 1980- '85 - '90 -'95 to remove that portion of demand supplied by gas plant liquids. Corresponding adjustments were not made to Imperial's provincial tables due to a lack of data.

(2) Shell's heavy fuel oil forecast was adjusted downward in accordance with supplementary material filed after the inquiry.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Atlantic

$(10^3 m^3/d)$

	Gulf	Imperial	Shell[1]	Texaco	Nova Scotia[2]	NEB
Motor Gasoline						
1978	8.4	8.3	8.1	8.3	-	8.4
1980	8.7	8.4	8.4	8.4	8.3	8.5
1985	9.2	8.3	8.1	8.3	7.8	8.4
1990	9.2	7.9	7.5	7.9	7.3	8.2
1995	9.4	7.9	7.3	7.6	7.2	7.9
Light Fuel Oil, Kerosene and Stove Oil						
1978	7.8	7.5	8.1	7.9	-	7.9
1980	7.3	7.2	8.1	7.5	8.1	7.6
1985	6.7	7.2	8.6	6.5	8.7	7.9
1990	6.7	7.5	8.6	6.4	7.1	8.3
1995	6.5	7.9	9.1	6.4	8.9	8.6
Diesel Fuel Oil						
1978	3.8	3.8	4.3	4.1	-	3.8
1980	4.0	4.3	4.8	4.4	4.1	4.1
1985	5.1	5.2	5.7	5.4	5.7	4.6
1990	6.2	6.7	6.7	6.4	6.8	5.4
1995	7.3	7.2	7.6	7.5	7.8	6.3
Heavy Fuel Oil						
1978	14.5	13.7	12.4	12.4	-	13.6
1980	14.0	15.7	12.2	12.7	13.5	14.9
1985	13.5	16.8	14.3	13.5	13.2	15.7
1990	14.5	17.8	14.9	14.3	12.7	14.4
1995	15.7	18.6	17.2	15.1	12.2	16.4
Petrochemical Feedstocks						
1978	0.2	-	-	0.2	-	0.1
1980	0.2	-	-	0.2	-	0.1
1985	0.2	-	-	0.2	-	0.1
1990	0.2	-	-	0.2	-	0.1
1995	0.3	-	-	0.2	-	0.1
Other Products						
1978	2.5	2.5	2.7	2.5	-	2.7
1980	2.5	2.7	2.5	2.7	2.4	3.0
1985	3.0	3.5	2.9	3.0	2.5	3.5
1990	3.3	4.4	3.2	3.5	2.7	4.1
1995	3.7	4.8	3.5	4.1	2.9	4.7
Total All Products						
1978	37.2	35.8	35.6	35.4	-	36.5
1980	37.0	38.3	36.1	35.9	36.2	38.2
1985	37.3	41.0	39.6	36.9	37.8	40.2
1990	39.9	44.3	40.8	38.6	38.6	40.5
1995	42.7	46.4	44.7	40.8	38.9	44.0

Note: Totals might not add due to rounding.

(1) Shell's heavy fuel oil forecast was adjusted downward in accordance with supplementary material filed after the inquiry.

(2) 1978 figures not available in Nova Scotia submission.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Quebec

$(10^3 m^3/d)$

Motor Gasoline	Gulf	Imperial	Shell	Texaco	Sun Oil	NEB
1978	23.7	23.2	23.8	23.5	23.7	24.1
1980	24.3	23.4	24.2	23.8	24.2	24.3
1985	23.2	22.1	22.6	23.8	23.4	22.7
1990	21.8	21.6	20.2	23.4	22.7	21.2
1995	21.0	21.3	19.1	22.7	22.7	20.2
Light Fuel Oil, Kerosene and Stove Oil						
1978	18.0	17.2	18.8	17.5	17.6	17.9
1980	17.0	16.2	18.4	16.4	17.5	17.5
1985	15.1	12.9	18.4	15.1	17.0	16.8
1990	13.8	9.9	18.4	14.3	16.8	16.6
1995	13.3	6.8	18.9	13.5	16.8	16.4
Diesel Fuel Oil						
1978	6.4	6.5	6.5	6.7	5.9	6.5
1980	6.8	6.8	7.3	7.6	6.4	6.8
1985	8.7	7.9	9.2	9.5	7.3	8.3
1990	10.8	9.4	11.4	11.6	8.4	9.9
1995	13.2	10.3	14.0	13.3	9.9	11.8
Heavy Fuel Oil						
1978	17.2	16.7	17.5	15.9	16.8	16.9
1980	17.0	17.5	18.3	14.9	17.5	18.8
1985	17.2	15.7	20.2	14.0	19.4	20.1
1990	17.2	16.7	21.8	13.2	21.3	21.0
1995	17.0	17.5	23.7	12.6	23.5	23.5
Petrochemical Feedstocks						
1978	3.5	3.5	3.7	3.8	-	3.0
1980	3.7	4.1	3.8	4.1	-	3.0
1985	4.1	5.6	4.0	4.8	-	5.5
1990	4.3	7.5	4.1	5.7	-	5.5
1995	4.3	9.7	4.3	6.8	-	5.5
Other Products						
1978	7.5	8.1	7.9	8.1	-	8.9
1980	7.6	8.7	8.4	8.4	-	9.4
1985	8.6	10.5	10.0	9.9	-	11.6
1990	9.7	12.6	11.1	11.4	-	13.4
1995	10.6	15.1	12.4	13.0	-	15.1
Total All Products						
1978	76.1	75.2	78.2	75.5	-	79.3
1980	76.3	76.7	80.4	75.3	-	79.8
1985	76.7	74.7	84.4	77.1	-	85.0
1990	77.4	77.5	87.1	79.6	-	87.6
1995	79.5	80.7	92.3	82.0	-	82.5

Note: Totals might not add due to rounding.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Ontario

$(10^3 m^3/d)$

Motor Gasoline	Gulf	Imperial	Shell (1)	Texaco	Sun Oil	NEB
1978	35.4	34.8	35.1	35.0	35.8	36.5
1980	36.5	35.0	35.4	35.4	37.5	37.1
1985	36.5	32.9	33.4	35.4	36.4	35.3
1990	34.5	32.3	31.3	34.8	35.3	32.9
1995	33.4	31.9	31.0	34.2	35.3	30.7
Light Fuel Oil, Kerosene and Stove Oil						
1978	14.3	14.8	15.4	15.1	15.1	14.8
1980	13.0	13.7	14.8	14.6	15.1	13.3
1985	10.3	9.7	14.1	14.1	14.9	12.3
1990	8.7	7.2	13.3	13.7	14.9	11.8
1995	7.8	5.6	13.3	13.2	14.9	11.4
Diesel Fuel Oil						
1978	8.3	8.3	8.4	8.3	8.6	8.1
1980	9.2	9.1	9.5	8.9	9.4	8.9
1985	11.9	11.1	12.6	10.6	11.0	11.4
1990	15.1	13.2	16.0	12.4	12.7	14.4
1995	18.6	15.3	20.2	14.0	14.6	17.9
Heavy Fuel Oil						
1978	12.1	12.6	11.3	13.5	12.4	11.9
1980	12.6	12.4	11.9	14.8	13.8	11.7
1985	12.4	9.4	13.2	15.9	13.5	11.7
1990	13.8	9.1	14.3	17.0	13.5	11.7
1995	15.3	8.7	15.7	18.3	13.8	12.1
Petrochemical Feedstocks						
1978	7.2	9.4	9.1	9.4	-	7.9
1980	8.6	11.8	9.9	10.3	-	10.8
1985	10.2	12.7	10.2	11.1	-	13.0
1990	11.0	14.6	10.2	11.9	-	16.5
1995	11.8	18.4	10.3	12.7	-	16.5
Other Products						
1978	10.5	9.7	9.7	11.4	-	11.4
1980	10.8	10.3	10.3	12.1	-	12.3
1985	12.2	12.4	11.9	14.3	-	14.3
1990	13.3	14.3	13.7	16.5	-	16.7
1995	14.9	16.7	15.7	18.6	-	19.0
Total All Products						
1978	87.7	89.5	89.0	92.6	-	90.6
1980	90.6	92.2	91.8	96.1	-	94.1
1985	93.4	88.2	95.3	101.5	-	98.0
1990	96.6	90.6	98.8	106.3	-	104.0
1995	101.7	96.6	106.3	110.9	-	107.6

Note: Totals might not add due to rounding.

(1) Shell's heavy fuel oil forecast was adjusted downward in accordance with supplementary material filed after the inquiry.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Manitoba

($10^3 m^3/d$)

Motor Gasoline	Gulf	Imperial [1]	Shell	Texaco	NEB
1978	4.4	-	4.6	4.4	4.5
1980	4.6	-	4.8	4.6	4.6
1985	4.3	-	4.4	4.3	4.5
1990	4.1	-	4.1	4.1	4.4
1995	4.0	-	4.0	3.8	4.4
Light Fuel Oil, Kerosene and Stove Oil					
1978	1.0	-	1.0	1.0	0.9
1980	0.8	-	1.0	1.0	0.9
1985	0.6	-	1.0	1.0	0.8
1990	0.6	-	0.8	0.8	0.8
1995	0.5	-	0.8	0.8	0.7
Diesel Fuel Oil					
1978	1.9	-	1.9	2.1	2.0
1980	2.1	-	2.1	2.2	2.1
1985	2.2	-	2.5	2.7	2.5
1990	2.5	-	2.9	3.2	3.0
1995	2.9	-	3.3	3.7	3.5
Heavy Fuel Oil					
1978	0.5	-	0.5	0.5	0.4
1980	0.5	-	0.5	0.5	0.4
1985	0.5	-	0.5	0.3	0.4
1990	0.5	-	0.5	0.3	0.4
1995	0.5	-	0.5	0.3	0.4
Petrochemical Feedstocks					
1978	-	-	-	-	-
1980	-	-	-	-	-
1985	-	-	-	-	-
1990	-	-	-	-	-
1995	-	-	-	-	-
Other Products					
1978	1.1	-	1.1	1.0	1.4
1980	1.1	-	1.1	1.3	1.4
1985	1.4	-	1.1	1.6	1.8
1990	1.6	-	1.3	1.7	2.0
1995	1.9	-	1.4	2.1	2.4
Total All Products					
1978	8.7	-	9.1	8.9	9.2
1980	9.1	-	9.4	9.5	9.4
1985	9.1	-	9.5	9.9	10.0
1990	9.1	-	9.5	10.2	10.6
1995	9.5	-	10.0	10.6	11.4

Note: Totals might not add due to rounding.

(1) Imperial only provided a forecast for the Prairies as a whole.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Saskatchewan

($10^3 m^3/d$)

Motor Gasoline	Gulf	Imperial[1]	Shell	Texaco	NEB
1978	5.9	-	5.9	5.6	5.8
1980	5.9	-	6.0	5.7	5.7
1985	5.7	-	6.0	5.6	5.5
1990	5.2	-	5.6	5.2	5.3
1995	4.9	-	5.7	4.9	5.1
Light Fuel Oil, Kerosene and Stove Oil					
1978	1.1	-	1.1	1.1	1.1
1980	1.0	-	1.0	1.1	1.1
1985	0.8	-	1.0	1.0	1.0
1990	0.6	-	1.0	1.0	1.0
1995	0.6	-	1.0	0.8	1.1
Diesel Fuel Oil					
1978	2.7	-	2.5	2.7	2.5
1980	2.9	-	2.9	2.9	2.7
1985	3.5	-	3.3	3.2	3.1
1990	4.1	-	4.0	3.7	3.8
1995	4.9	-	4.6	4.1	4.4
Heavy Fuel Oil					
1978	0	-	-	-	0.1
1980	0	-	-	-	0
1985	0	-	-	-	0
1990	0	-	-	-	0
1995	0	-	-	-	0.1
Petrochemical Feedstocks					
1978	-	-	-	-	-
1980	-	-	-	-	-
1985	-	-	-	-	-
1990	-	-	-	-	-
1995	-	-	-	-	-
Other Products					
1978	1.1	-	1.3	1.1	1.0
1980	1.1	-	1.3	1.3	1.2
1985	1.3	-	1.4	1.6	1.4
1990	1.4	-	1.4	1.9	1.6
1995	1.6	-	1.4	2.2	2.0
Total All Products					
1978	10.5	-	10.6	10.5	10.6
1980	10.8	-	11.1	11.0	10.7
1985	11.1	-	11.8	11.3	11.0
1990	11.4	-	11.9	11.8	11.7
1995	11.9	-	12.7	12.1	12.7

Note: Totals might not add due to rounding.

(1) Imperial only provided a forecast for the Prairies as a whole.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Alberta

($10^3 m^3/d$)

Motor Gasoline	Gulf	Imperial[(1)]	Shell	Texaco	NEB
1978	11.4	-	11.8	11.6	11.7
1980	12.1	-	12.9	12.1	12.4
1985	12.4	-	13.8	12.2	13.1
1990	12.6	-	13.3	11.8	13.4
1995	12.7	-	13.7	11.3	13.5
Light Fuel Oil, Kerosene and Stove Oil					
1978	0.6	-	0.6	0.5	0.5
1980	0.5	-	0.6	0.5	0.5
1985	0.5	-	0.6	0.5	0.4
1990	0.5	-	0.5	0.5	0.4
1995	0.3	-	0.5	0.5	0.4
Diesel Fuel Oil					
1978	5.7	-	5.6	5.7	5.3
1980	6.5	-	6.5	6.2	5.5
1985	8.3	-	8.4	7.3	7.1
1990	10.2	-	10.0	8.3	8.9
1995	12.2	-	12.9	9.1	11.1
Heavy Fuel Oil					
1978	0	-	-	0.2	0.1
1980	0	-	0.2	0.2	0.1
1985	0	-	0.2	0.2	0.2
1990	0	-	0.2	0.2	0.2
1995	0	-	0.2	0.2	0.2
Petrochemical Feedstocks					
1978	-	-	-	0.3	0
1980	3.2	-	0.8	0.3	0
1985	3.2	-	1.6	3.5	3.2
1990	3.2	-	4.8	3.8	3.2
1995	3.2	-	7.9	3.8	3.2
Other Products					
1978	4.3	-	6.2	5.4	5.0
1980	4.4	-	6.7	6.4	5.5
1985	5.1	-	8.1	7.3	6.7
1990	6.0	-	10.0	8.1	7.9
1995	6.8	-	11.0	8.9	9.0
Total All Products					
1978	22.1	-	24.2	23.7	22.6
1980	26.7	-	27.6	25.6	24.0
1985	29.6	-	32.7	31.0	30.7
1990	32.4	-	38.8	32.6	34.0
1995	35.4	-	46.1	33.7	37.3

Note: Totals might not add due to rounding.

(1) Imperial only provided a forecast of the Prairies as a whole.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Prairies

($10^3 m^3/d$)

Motor Gasoline	Gulf	Imperial	Shell	Texaco	NEB
1978	21.8	21.6	22.1	21.6	22.0
1980	22.6	22.1	23.7	22.4	22.7
1985	22.4	21.6	24.3	21.1	23.1
1990	21.9	21.3	23.0	21.1	23.1
1995	21.6	21.0	23.4	20.0	23.0
Light Fuel Oil, Kerosene and Stove Oil					
1978	2.7	3.2	2.7	2.5	2.5
1980	2.2	2.9	2.5	2.5	2.5
1985	1.9	2.7	2.5	2.4	2.2
1990	1.7	2.7	2.2	2.2	2.2
1995	1.4	2.7	2.2	2.1	2.2
Diesel Fuel Oil					
1978	10.3	10.8	10.0	10.5	9.8
1980	11.4	11.9	11.4	11.3	10.3
1985	14.0	15.1	14.3	13.2	12.7
1990	16.8	18.4	16.8	15.1	15.7
1995	20.0	23.7	20.8	16.8	18.9
Heavy Fuel Oil					
1978	0.5	0.5	0.5	0.6	0.6
1980	0.5	0.5	0.6	0.6	0.5
1985	0.5	0.5	0.6	0.5	0.6
1990	0.5	0.5	0.6	0.5	0.6
1995	0.5	0.5	0.6	0.5	0.7
Petrochemical Feedstocks					
1978	-	0.6	-	0.3	0
1980	3.2	2.4	0.8	0.3	0
1985	3.2	5.9	1.6	3.5	3.2
1990	3.2	11.4	4.8	3.8	3.2
1995	3.2	11.4	7.9	3.8	3.2
Other Products					
1978	6.5	9.2	8.6	7.5	7.4
1980	6.7	9.4	9.1	8.9	8.1
1985	7.8	10.6	10.6	10.5	9.9
1990	9.1	11.9	12.7	11.8	11.5
1995	10.3	13.2	13.8	13.2	13.4
Total All Products					
1978	41.3	45.9	43.9	43.1	42.4
1980	46.6	49.1	48.1	46.1	44.1
1985	49.7	56.4	54.0	52.1	51.7
1990	52.9	66.3	60.2	54.5	56.3
1995	56.9	72.5	68.8	56.4	61.4

Note: Totals might not add due to rounding.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - British Columbia

($10^3 m^3/d$)

Motor Gasoline	Gulf	Imperial(1)	Shell(2)	Texaco	B.C.(3)	NEB
1978	10.8	10.6	10.6	10.6	10.6	10.4
1980	11.3	11.0	11.3	11.1	11.3	10.8
1985	11.0	10.8	12.2	11.1	11.9	11.6
1990	10.5	10.6	12.2	10.8	12.4	12.3
1995	10.3	10.5	12.4	10.3	13.0	13.3
Light Fuel Oil, Kerosene and Stove Oil						
1978	2.9	2.9	3.0	3.0	3.7	3.2
1980	2.7	2.7	3.0	2.9	3.8	3.3
1985	2.2	2.2	3.0	2.9	4.4	3.2
1990	2.1	2.1	2.9	2.5	4.4	3.2
1995	1.7	1.7	2.9	2.4	4.8	3.1
Diesel Fuel Oil						
1978	5.2	5.2	5.4	5.1	5.1	5.3
1980	5.7	5.6	5.9	5.6	5.6	5.9
1985	7.2	6.8	7.8	6.8	6.7	7.0
1990	8.7	8.3	9.2	8.1	7.3	8.4
1995	10.3	9.5	11.1	9.2	8.1	10.4
Heavy Fuel Oil						
1978	3.8	3.7	3.8	4.1	4.3	3.7
1980	3.8	3.8	3.7	4.4	4.8	3.9
1985	4.1	2.5	4.3	5.1	5.4	4.7
1990	4.3	2.9	4.6	5.9	5.7	4.9
1995	4.4	3.0	5.1	6.7	6.2	5.7
Petrochemical Feedstocks						
1978	0.2	0.2	0.2	0.2	0.2	0.1
1980	0.2	0.3	0.2	0.2	0.2	0.1
1985	0.2	0.3	0.2	0.2	0.2	0.1
1990	0.2	0.5	0.2	0.2	0.2	0.1
1995	0.2	0.6	0.2	0.2	0.3	0.1
Other Products						
1978	3.5	4.0	3.2	4.0	3.3	4.0
1980	3.8	4.1	3.5	4.3	3.7	4.4
1985	4.1	4.8	4.3	5.1	4.8	5.4
1990	4.9	5.7	4.9	5.7	5.9	6.2
1995	5.6	6.5	5.9	6.4	7.2	7.2
Total All Products						
1978	26.4	26.5	26.2	27.0	27.3	26.7
1980	27.5	27.5	27.5	28.4	29.4	28.4
1985	28.8	27.5	31.8	31.1	33.1	32.0
1990	30.3	30.0	34.0	33.2	36.1	35.1
1995	32.6	31.9	37.5	35.1	39.4	39.8

Note: Totals might not add due to rounding.

(1) Imperial provided a forecast for the Pacific Region.

(2) Shell's heavy fuel oil forecast was adjusted downward in accordance with supplementary material filed after the inquiry.

(3) Forecast submitted by the Province of British Columbia.

NET SALES OF REFINED PETROLEUM PRODUCTS

Comparison of Forecasts - Yukon & N.W.T.

($10^3 m^3/d$)

Motor Gasoline	Gulf	Imperial (1)	Shell	Texaco	NEB
1978	0.3	-	0.3	0.3	0.3
1980	0.3	-	0.3	0.3	0.3
1985	0.3	-	0.3	0.3	0.3
1990	0.3	-	0.3	0.3	0.3
1995	0.5	-	0.3	0.3	0.3
Light Fuel Oil, Kerosene and Stove Oil					
1978	0.5	-	0.5	0.5	0.5
1980	0.5	-	0.6	0.5	0.5
1985	0.5	-	0.6	0.6	0.5
1990	0.5	-	0.8	0.8	0.5
1995	0.5	-	1.0	0.8	0.4
Diesel Fuel Oil					
1978	0.6	-	0.6	0.6	0.6
1980	0.8	-	0.6	0.8	0.7
1985	0.8	-	0.8	1.0	0.8
1990	1.0	-	1.0	1.3	1.0
1995	1.1	-	1.1	1.4	1.2
Heavy Fuel Oil					
1978	0.2	-	-	0.2	0.1
1980	0.2	-	-	0.2	0.1
1985	0.2	-	-	0.3	0.1
1990	0.2	-	-	0.3	0.1
1995	0.2	-	-	0.3	0.1
Petrochemical Feedstocks					
1978	-	-	-	-	-
1980	-	-	-	-	-
1985	-	-	-	-	-
1990	-	-	-	-	-
1995	-	-	-	-	-
Other Products					
1978	0.3	-	0.3	0.3	0.4
1980	0.3	-	0.3	0.3	0.5
1985	0.3	-	0.5	0.5	0.6
1990	0.3	-	0.5	0.5	0.7
1995	0.5	-	0.6	0.6	0.8
Total All Products					
1978	1.6	-	1.7	1.9	1.9
1980	1.7	-	1.9	2.1	2.1
1985	1.9	-	2.2	2.7	2.3
1990	2.2	-	2.5	3.2	2.6
1995	2.4	-	3.0	3.5	2.8

Note: Totals might not add due to rounding.

(1) Imperial did not submit Yukon & N.W.T. figures.

1978 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

COMPARISON OF FORECASTS*

$10^3m^3/d$

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	121.6	117.9	122.5	119.0	122.4	134.3
Deduct Product Imports	-	2.2	3.2	4.1	1.3	1.3
Add Product Exports	-	0.3	0.9	7.0	3.5	3.5
Net Product Transfers Out/(In)	3.0	4.3	-	2.9	1.6	1.6
Losses, Industry Use and Other Adjustments	8.7	8.1	7.6	9.8	8.4	9.2
Deduct Gas Plant Butanes Supplied to Refineries	-	-	-	-	-	-
Total Requirements	133.3	128.4	127.9	134.6	135.1	147.1
West of the Ottawa Valley Line						
Total Market Product Sales	148.7	154.9	151.7	156.5	153.0	160.6
Deduct Product Imports	0.8	-	0.9	2.4	1.9	1.9
Add Product Exports	7.3	31.8	2.4	12.1	6.0	6.0
Net Product Transfers Out/(In)	(3.0)	(4.3)	-	(2.9)	(1.6)	(1.6)
Losses, Industry Use and Other Adjustments	6.4	(18.4)	9.4	9.1	6.8	7.3
Deduct Gas Plant Butanes Supplied to Refineries	2.9	2.5	3.5	2.5	4.0	4.0
Total Requirements	155.7	161.4	159.1	169.9	158.1	166.7
Canada						
Total Market Product Sales	270.3	272.8	274.3	275.5	275.4	294.9
Deduct Product Imports	0.8	2.2	4.1	6.5	3.2	3.2
Add Product Exports	7.3	32.1	3.3	19.1	9.5	9.5
Losses, Industry Use and Other Adjustments	15.1	(10.3)	17.0	18.9	15.2	16.5
Deduct Gas Plant Butanes Supplied to Refineries	2.9	2.5	3.5	2.5	4.0	4.0
Total Requirements	289.0	289.8	287.0	304.5	293.2	313.8

* Totals might not add because of rounding.

1979 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

COMPARISON OF FORECASTS*

$10^3m^3/d$

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	121.7	120.8	125.1	118.9	124.3	139.2
Deduct Product Imports	-	-	4.0	3.7	1.1	1.1
Add Product Exports	-	0.3	1.0	7.0	2.9	2.9
Net Product Transfers Out/(In)	3.2	2.4	-	2.1	1.4	1.4
Losses, Industry Use and Other Adjustments	8.4	8.3	7.8	9.4	8.6	9.5
Deduct Gas Plant Butanes Supplied to Refineries	-	-	-	-	-	-
Total Requirements	133.3	131.7	129.8	133.6	136.8	151.4
West of the Ottawa Valley Line						
Total Market Product Sales	152.2	157.5	156.2	161.1	156.7	166.7
Deduct Product Imports	0.5	0.2	1.7	2.7	1.9	1.9
Add Product Exports	7.3	36.2	0.9	12.7	5.4	5.4
Net Product Transfers Out/(In)	(3.2)	(2.4)	-	(2.1)	(1.4)	(1.4)
Losses, Industry Use and Other Adjustments	6.4	(22.4)	9.8	8.2	6.8	7.3
Deduct Gas Plant Butanes Supplied to Refineries	2.9	2.5	3.5	2.5	4.0	4.0
Total Requirements	159.4	166.2	161.8	174.8	161.0	172.4
Canada						
Total Market Product Sales	273.9	278.2	281.3	280.0	281.0	305.9
Deduct Product Imports	0.5	0.2	5.7	6.4	3.0	3.0
Add Product Exports	7.3	36.5	1.9	19.7	8.3	8.3
Losses, Industry Use and Other Adjustments	14.8	(14.1)	17.6	17.6	15.4	16.8
Deduct Gas Plant Butanes Supplied to Refineries	2.9	2.5	3.5	2.5	4.0	4.0
Total Requirements	292.7	297.9	291.6	308.4	297.8	323.8

* Totals might not add because of rounding.

1980 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

COMPARISON OF FORECASTS*

$10^3 m^3/d$

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	121.6	122.4	125.2	119.3	126.6	142.9
Deduct Product Imports	-	-	3.0	3.7	1.1	1.1
Add Product Exports	-	0.3	1.0	7.0	3.0	3.0
Net Product Transfers Out/(In)	(3.7)	0.5	-	1.9	1.3	1.3
Losses, Industry Use and Other Adjustments	8.4	8.3	7.6	9.4	8.6	9.7
Deduct Gas Plant Butanes Supplied to Refineries	-	-	-	-	-	-
Total Requirements	126.3	131.4	130.8	134.0	137.8	155.2
West of the Ottawa Valley Line						
Total Market Product Sales	157.8	157.0	161.0	164.6	159.8	172.5
Deduct Product Imports	0.3	0.2	2.2	2.7	2.1	2.1
Add Product Exports	2.7	43.2	-	12.7	5.4	5.4
Net Product Transfers Out/(In)	3.7	(0.5)	-	(1.9)	(1.3)	(1.3)
Losses, Industry Use and Other Adjustments	6.5	(26.7)	10.0	8.4	7.0	7.6
Deduct Gas Plant Butanes Supplied to Refineries	2.9	2.5	3.5	2.4	4.4	4.4
Total Requirements	167.5	170.3	165.3	178.8	164.1	178.3
Canada						
Total Market Product Sales	278.7	279.3	286.2	284.0	286.4	315.4
Deduct Product Imports	0.3	0.2	5.2	6.4	3.2	3.2
Add Product Exports	2.7	43.5	1.0	19.7	8.4	8.4
Losses, Industry Use and Other Adjustments	14.9	(18.4)	17.6	17.8	15.6	17.3
Deduct Gas Plant Butanes Supplied to Refineries	2.9	2.5	3.5	2.4	4.4	4.4
Total Requirements	293.8	301.8	296.0	312.7	301.9	333.5

* Totals might not add because of rounding.

1985 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

COMPARISON OF FORECASTS*

$10^3 m^3/d$

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	122.8	122.5	133.2	122.5	136.5	165.4
Deduct Product Imports	–	–	5.6	3.7	1.3	1.3
Add Product Exports	–	0.3	2.4	7.0	2.5	2.5
Net Product Transfers Out/(In)	(3.2)	0.3	–	1.0	1.3	1.3
Losses, Industry Use and Other Adjustments	8.4	8.0	8.1	9.5	9.2	11.1
Deduct Gas Plant Butanes Supplied to Refineries	–	–	–	–	–	–
Total Requirements	128.1	131.1	138.1	136.3	145.9	178.1
West of the Ottawa Valley Line						
Total Market Product Sales	165.1	156.2	174.0	178.9	175.0	205.7
Deduct Product Imports	0.5	0.2	2.5	5.4	2.5	2.5
Add Product Exports	2.2	33.5	0.2	14.3	5.6	5.6
Net Product Transfers Out/(In)	3.2	(0.3)	–	(1.0)	(1.3)	(1.3)
Losses, Industry Use and Other Adjustments	6.5	(18.9)	10.5	9.2	7.5	8.9
Deduct Gas Plant Butanes Supplied to Refineries	2.9	2.7	3.5	1.9	4.4	4.4
Total Requirements	173.7	167.6	178.6	194.2	179.7	212.8
Canada						
Total Market Product Sales	288.1	278.7	307.2	301.4	311.5	371.1
Deduct Product Imports	0.5	0.2	8.1	9.1	3.8	3.8
Add Product Exports	2.2	33.8	2.6	21.3	8.1	8.1
Losses, Industry Use and Other Adjustments	14.9	(11.0)	18.6	18.7	16.7	20.0
Deduct Gas Plant Butanes Supplied to Refineries	2.9	2.7	3.5	1.9	4.4	4.4
Total Requirements	301.8	298.7	316.7	330.5	325.6	390.9

* Totals might not add because of rounding.

1990 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

COMPARISON OF FORECASTS*

$10^3m^3/d$

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	126.2	128.7	137.6	127.1	137.1	186.8
Deduct Product Imports	-	-	8.1	3.7	1.1	1.1
Add Product Exports	-	0.3	7.0	7.0	2.5	2.5
Net Product Transfers Out/(In)	(3.0)	-	-	1.0	1.1	1.1
Losses, Industry Use and Other Adjustments	8.4	8.1	8.6	9.9	9.4	12.5
Deduct Gas Plant Butanes Supplied to Refineries	-	-	-	-	-	-
Total Requirements	131.6	137.1	145.1	141.3	149.2	200.2

West of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	173.0	164.5	186.1	188.3	188.4	239.4
Deduct Product Imports	1.7	0.3	12.2	5.4	2.9	2.9
Add Product Exports	2.2	16.2	2.5	14.3	5.1	5.1
Net Product Transfers Out/(In)	3.0	-	-	(1.0)	(1.1)	(1.1)
Losses, Industry Use and Other Adjustments	6.4	(5.2)	11.1	9.5	8.1	10.5
Deduct Gas Plant Butanes Supplied to Refineries	2.7	2.7	3.5	1.6	4.4	4.4
Total Requirements	180.2	172.4	184.0	204.2	193.5	248.0

Canada	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	299.2	293.2	323.7	315.4	325.5	426.2
Deduct Product Imports	1.7	0.3	20.3	9.1	4.0	4.0
Add Product Exports	2.2	16.5	9.5	21.3	7.6	7.6
Losses, Industry Use and Other Adjustments	14.8	2.7	19.7	19.4	17.5	23.0
Deduct Gas Plant Butanes Supplied to Refineries	2.7	2.7	3.5	1.6	4.4	4.4
Total Requirements	311.8	309.5	329.1	345.4	342.7	448.3

* Totals might not add because of rounding.

1995 REQUIREMENTS FOR CRUDE OIL AND EQUIVALENT

COMPARISON OF FORECASTS*

$10^3m^3/d$

East of the Ottawa Valley Line	Gulf	Imperial	Shell	Texaco	NEB Forecast	NEB Export Formula
Total Market Product Sales	131.4	134.3	147.8	131.9	146.0	208.4
Deduct Product Imports	-	-	14.3	3.7	1.1	1.1
Add Product Exports	-	-	13.3	7.0	2.1	2.1
Net Product Transfers Out/(In)	(3.2)	(0.3)	-	1.0	1.0	1.0
Losses, Industry Use and Other Adjustments	8.4	7.9	9.4	10.0	10.0	14.1
Deduct Gas Plant Butanes Supplied to Refineries	-	-	-	-	-	-
Total Requirements	136.7	141.9	156.2	146.2	158.3	222.8
West of the Ottawa Valley Line						
Total Market Product Sales	184.0	185.4	205.0	196.9	201.8	272.1
Deduct Product Imports	3.7	0.5	19.2	5.4	3.2	3.2
Add Product Exports	2.2	10.8	7.5	14.3	5.1	5.1
Net Product Transfers Out/(In)	3.2	0.3	-	(1.0)	(1.0)	(1.0)
Losses, Industry Use and Other Adjustments	6.8	(7.5)	11.9	10.0	8.6	11.8
Deduct Gas Plant Butanes Supplied to Refineries	2.7	2.7	3.5	1.6	4.4	4.4
Total Requirements	189.9	185.9	201.6	213.2	206.7	282.7
Canada						
Total Market Product Sales	315.4	311.8	352.8	328.8	347.8	480.5
Deduct Product Imports	3.7	0.5	33.5	9.1	4.3	4.3
Add Product Exports	2.2	10.8	20.8	21.3	7.2	7.2
Losses, Industry Use and Other Adjustments	15.2	8.4	21.3	20.0	18.6	25.9
Deduct Gas Plant Butanes Supplied to Refineries	2.7	2.7	3.5	1.6	4.4	4.4
Total Requirements	326.5	327.8	357.8	359.4	365.0	505.5

* Totals might not add because of rounding.

MONTREAL[1] AND WOV REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT HYDROCARBONS

NEB Forecast

$10^3m^3/d$

	Light Crude Oil	Pentanes Plus	Synthetic Crude Oil	Total Light Crude and Equivalent[2]	Heavy Crude Oil	Total[2]
1978	158.4	10.3	11.1	179.9	18.0	197.8
1979	149.5	10.3	21.5	181.3	19.4	200.7
1980	150.5	10.3	23.0	183.8	20.0	203.9
1985	135.9	16.7	42.9	195.4	24.0	219.4
1990	98.8	16.7	89.8	205.3	28.0	233.3
1995	75.3	16.7	122.4	214.4	32.1	246.5

(1) Based on shipments of 39.7 x $10^3m^3/d$ to Montreal.

(2) Totals may not add because of rounding.

MONTREAL[1] AND WOV REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT HYDROCARBONS

NEB Forecast

$10^3m^3/d$

	Light Crude Oil	Pentanes Plus	Synthetic Crude Oil	Total Light Crude and Equivalent[2]	Heavy Crude Oil	Total[2]
1978	158.4	10.3	11.1	179.9	18.0	197.8
1979	163.8	10.3	21.5	195.6	21.0	216.6
1980	164.8	10.3	23.0	198.1	21.6	219.8
1985	149.8	16.7	42.9	209.4	25.9	235.3
1990	112.5	16.7	89.8	219.0	30.2	249.2
1995	88.7	16.7	122.4	227.7	34.6	262.3

(1) Based on shipments of 55.6 x $10^3m^3/d$ to Montreal.

(2) Totals may not add because of rounding.

MONTREAL REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT HYDROCARBONS

NEB Forecast - 39.7 x $10^3 m^3/d$ Case

	Light Crude Oil	Pentanes Plus	Synthetic Crude Oil	Total Light Crude and Equivalent(1)	Heavy Crude Oil	Other	Total(1)
1978	31.3	1.3	2.4	35.0	4.8	-	39.7
1979	27.0	0.8	5.6	33.4	6.4	-	39.7
1980	26.5	1.3	5.6	33.4	6.4	-	39.7
1985	20.0	1.3	11.1	32.4	7.3	-	39.7
1990	7.8	1.3	22.2	31.3	8.4	-	39.7
1995	-	1.3	28.9	30.2	9.5	-	39.7

(1) Totals may not add because of rounding.

MONTREAL REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT HYDROCARBONS

NEB Forecast - 55.6 x $10^3 m^3/d$ Case

	Light Crude Oil	Pentanes Plus	Synthetic Crude Oil	Total Light Crude and Equivalent(1)	Heavy Crude Oil	Other	Total(1)
1978	31.3	1.3	2.4	35.0	4.8	-	39.7
1979	42.1	0.8	5.6	48.5	7.2	-	55.6
1980	41.6	1.3	5.6	48.5	7.2	-	55.6
1985	35.0	1.3	11.1	47.4	8.3	-	55.6
1990	22.6	1.3	22.2	46.1	9.5	-	55.6
1995	13.3	1.3	30.2	44.8	10.8	-	55.6

(1) Totals may not add because of rounding.

WOV REQUIREMENTS FOR INDIGENOUS CRUDE OIL AND EQUIVALENT HYDROCARBONS

NEB Forecast

$10^3 m^3/d$

	Light Crude Oil	Pentanes Plus	Synthetic Crude Oil(1)	Total Light Crude and Equivalent(2)	Heavy Crude Oil	Total(2)
1978	127.1	9.1	8.7	144.9	13.2	158.1
1979	121.7	9.5	15.9	147.1	13.8	161.0
1980	123.1	9.1	17.5	149.7	14.5	164.1
1985	114.9	15.4	31.8	162.1	17.6	179.7
1990	89.9	15.4	67.5	172.9	20.7	193.5
1995	75.3	15.4	92.2	182.9	23.8	206.7

(1) Includes synthetic crude oil sold directly as diesel fuel.

(2) Totals may not add because of rounding.

REQUIREMENTS FOR INDIGENOUS HEAVY CRUDE OIL

NEB Forecast

$10^3 m^3/d$

Year	WOV Requirements for Asphalt-Yielding Crude Oil	Other WOV Requirements	Total WOV(1)	Montreal Requirements		Total Canada	
				250 Case	350 Case	250 Case	350 Case
1978	8.7	4.4	13.2	4.8	4.8	18.0	18.0
1979	9.4	4.4	13.8	5.6	7.2	19.4	21.0
1980	10.0	4.4	14.5	5.6	7.2	20.0	21.6
1985	13.2	4.4	17.6	6.4	8.3	24.0	25.9
1990	16.2	4.4	20.7	7.3	9.5	28.0	30.2
1995	19.4	4.4	23.8	8.3	10.8	32.1	34.6

(1) Totals may not add because of rounding.

SUPPLY AND REQUIREMENTS FOR SEGREGATED PENTANES PLUS

Comparison of Forecasts

$10^3 m^3/d$

	Supply		Requirements				
			NEB			Submittors[2]	
	Pentanes Plus Total Supply	Segregated Net Supply[1]	Heavy Crude Blending	Refinery & Petrochemical[2]	Total[3]	Gulf	Shell
1978	20.5	15.6	1.7	10.3	12.1	11.4	11.8
1979	20.2	15.3	1.9	10.3	12.2	11.6	15.9
1980	19.7	15.3	2.1	10.3	12.4	15.9	17.3
1985	16.2	13.0	1.7	16.7	18.4	16.7	14.5
1990	11.4	9.5	2.4	16.7	19.1	12.7	14.0
1995	7.6	6.0	2.7	16.7	19.4	8.4	15.9

(1) Supply net of volumes blended into light crude oil streams and volumes locationally constrained to the export market.

(2) Submittors forecasts correspond to NEB refinery and petrochemical forecast.

(3) Totals may not add because of rounding.

REQUIREMENTS FOR SYNTHETIC OIL
Comparison of Forecasts

$10^3 m^3/d$

	1978			1979			1980		
	Montreal	WOV	Total[3]	Montreal	WOV	Total[3]	Montreal	WOV	Total[3]
Gulf	4.0	11.9	15.9	11.1	13.5	24.6	13.2	12.2	25.4
Imperial	1.6	3.7	5.2	3.2	14.9	18.1	2.5	15.7	18.3
Shell[1]	2.4	10.3	12.7	4.8	19.1	23.8	5.1	22.7	27.9
NEB[2]	2.4	8.7	11.1	5.7	15.9	21.5	5.6	17.5	23.0

	1985			1990			1995		
	Montreal	WOV	Total[3]	Montreal	WOV	Total[3]	Montreal	WOV	Total[3]
Gulf	23.8	27.0	50.8	25.3	62.9	88.2	29.4	67.5	96.9
Imperial	5.7	24.6	30.3	11.1	48.5	59.6	11.1	59.6	70.7
Shell[1]	-	30.2	30.2	5.7	88.0	93.8	18.4	133.3	151.7
NEB[2]	11.1	31.8	42.9	22.2	67.5	89.8	30.2	92.2	122.4

(1) Includes Syncrude, Cold Lake, and Bitumen; excludes GCOS.

(2) Includes supply from upgraded heavy crude oil but excludes that from in situ pilots.

(3) Totals may not add because of rounding.

2474